Annual Report 1989

Public Utilities Board
Alberta

90-06051/

Public Utilities Board
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March 30, 1990

The Honourable Donald Getty
President of the Executive Council
of Alberta
Legislature Building
Edmonton, Alberta

1989 ANNUAL REPORT

Dear Sir:

We have the honour to submit herewith the Annual Report of the Public Utilities Board for the year 1989.

In addition to providing the information which is required by statute, this Report provides a brief description of the Board and its responsibilities and highlights significant activities and developments which occurred during 1989.

Yours respectfully,

A.O. Ackroyd - Chairman

A. Jah - Member

N.W. MacDonald - Member

A. Calista Barfett - Member

R.D.S. Ward - Member

T. Donald Hetherington - Member

J.R. Dunstan - Member

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Message from the Chairman

I am pleased to present the Board's 1989 Annual Report.

1989 proved to be a momentous year. Widespread attention was focused on the Board early in the year when it issued its decision respecting prices at which Alberta Power, TransAlta and Edmonton Power would sell electric energy to the Electric Energy Marketing Agency in 1989. In its decision, the Board concluded that Edmonton Power's Genesee 2 plant was not required in 1989, and hence excluded its cost from Edmonton Power's 1989 costs to the Agency. This decision was appealed to the Alberta Court of Appeal, whose judgement was not rendered during 1989. Towards the end of the year, in its decision respecting prices at which the utilities would sell electric energy to the Electric Energy Marketing Agency in 1990, the Board allowed the inclusion of Genesee 2, but excluded the costs of the second unit of the Sheerness power plant, which is jointly owned by Alberta Power and TransAlta.

Both TransAlta and Alberta Power were also before the Board in 1989 with rate proceedings. In its Phase I Decisions, issued December 15, 1989, the Board denied the utilities' requests for increases of approximately 7% in the average level of consumer rates in 1990, concluding that the utilities' existing rates would provide a fair return to shareholders in 1990, while enabling the utilities to maintain existing service levels.

While the Board was faced with an extremely busy electrical agenda in 1989, another facet of its regulatory workload was terminated. On August 14, 1989, the Supreme Court of Canada ruled that Alberta Government Telephones was an interprovincial undertaking, and therefore outside of the Board's jurisdiction. However, in another aspect of its decision, the Supreme Court ruled that AGT, as a Crown Corporation, was not brought under the jurisdiction of the Canadian Radio-television and Telecommunications Commission by the current legislative scheme, thereby creating a regulatory vacuum respecting AGT. This led to the creation of a Ministerial Committee on Telecommunications by the Minister of Technology, Research and Telecommunications. Certain members of this Board have been appointed to this committee, which advises the Minister on various telecommunications issues.

In 1989, the Board also renewed its efforts to ensure that the regulatory process continues to evolve in the best interests of the public. In light of its growing concern over the costs associated with rate proceedings, in May of 1989 the Board issued a Scale of Costs. This scale sets a cap on professional fees and prescribes allowable disbursements which may be claimed by participants in Board hearings. Further, as the culmination of its review of the regulatory process which the Board initiated in 1988, the Board issued its Procedural Review Report on June 30, 1989. This report, which has been given widespread distribution, sets out the Board's position on certain important topical issues, including rules of practice, costs awards, the use of plain language, and the hearing process. In addition, to foster greater public understanding of its role, the Board has continued to work with the Edmonton Public School Board on the creation of a course to explain utility ratemaking to Alberta students.

I would like to close by thanking the staff for their hard work throughout the year, which contributed to the Board's success. As the Board embarks upon its 75th year of operations, I am certain that it is well-equipped to meet the challenges that lie ahead.

A.O. Ackroyd

A.O. Ackroyd, Q.C.
Chairman

Mandate of the Board

The Public Utilities Board was created by the Alberta Legislature in 1915. The basic purpose of the Board is to protect the public interest by fixing just and reasonable rates for utility services. The need for regulation arises because utilities generally provide necessary services on a monopoly basis. In light of the large investment required in plant to provide utility service, it is not economically viable for more than one utility company to supply service within a given franchise area. This absence of competition for the services provided by utility companies resulted in the establishment of an independent tribunal to ensure that utility rates are set at a level that is fair to both the customers and the investors in the utility.

The main function of the Board is to balance the interests of the consuming public and the utility companies. It must permit the utility the opportunity to earn sufficient revenues through customer rates to recover its costs of providing the service which includes a fair return on its investment in utility property and plant, while ensuring that these rates are just and reasonable and the quality of service is safe and adequate.

It must be noted that there are different levels of regulation. The Board has the jurisdiction to establish rates and terms and conditions of service for public and gas utilities, as defined in the statutes. However, in 1989 the Supreme Court of Canada ruled that Alberta Government Telephones was an interprovincial undertaking, and hence outside the jurisdiction of the Board. Further details respecting this ruling and its ramifications are found in the Telecommunications Section of the Report.

In addition, the Board has only limited jurisdiction respecting municipally-owned utilities and natural gas co-operatives. The Board's authority is limited to hearing certain specific consumer complaints with respect to the rates set by these noninvestor-owned utilities.

A listing of all utilities which fall under the full jurisdiction of the Board is contained in Appendix 4.

The Board derives its authority primarily from the Public Utilities Board Act and the Gas Utilities Act. These statutes provide the Board with explicit directions as to how it may set rates for those utilities under its full jurisdiction.

Firstly, the Board is required to set a rate base for the utility. This involves a determination of the amount of money net of depreciation the utility company has invested over the years in its facilities which are required to provide service to the public within Alberta. The Board must then establish a fair return on this rate base, which is essentially equivalent to the annual cost of the capital invested in that rate base. The utility company's reasonable operating expenses as approved by the Board are added together with the fair return to establish the utility's revenue requirement. This represents the amount of money the company will need to have an opportunity to collect from utility sales in order to pay expenses and earn its fair return. Finally, the Board must determine how the revenue requirement should be allocated among the different types or classes of customers - residential, commercial and industrial. While the statutes do not provide the Board with much guidance respecting rate design, they do specify that these rates may not be unjustly discriminatory or unduly preferential. As part of the general rate application process, the Board also reviews the utility's terms and conditions of service, to ensure that fair and reliable service will be provided to customers.

This form of rate base - rate of return regulation has been used almost universally by regulatory tribunals in Canada and the United States. In recent years some critics in the regulatory field have argued that it is inflexible, and offers no incentive for utilities to increase productivity. Some jurisdictions have

experimented with refinements and alternatives, such as social contracts, price caps and incentive regulation. None are without their faults, and may require regulators to fall back on conventional regulation from time to time. The legislation in place in Alberta would not allow the Board to adopt some of the alternatives.

While the Board's primary function is to set rates for investor-owned public and gas utilities, the Board performs a variety of other functions pursuant to more than thirty Alberta statutes. These responsibilities are outlined later in this Report.

Organization of the Board

The Public Utilities Board is an administrative tribunal with quasi-judicial powers. In dealing with the matters which the Legislature has assigned to it, the Board has been granted the same status as the Alberta Court of Queen's Bench.

While the Board has been granted the authority to establish its own procedures, there are certain restrictions on its conduct. For example, the Board is subject to the Administrative Procedures Act, which requires, among other things, that the Board give adequate notice to all affected parties; that all parties who may be adversely affected by an application before the Board be afforded an opportunity to furnish relevant evidence and to present argument; and that the Board give written reasons for its decisions.

The decisions of the Board may also be reviewed or appealed. Pursuant to Section 62 of the Public Utilities Board Act, an application for leave to appeal a decision or order of the Board may be made to the Alberta Court of Appeal, and subsequently to the Supreme Court of Canada, on questions of jurisdiction or law, but not on findings of fact. The Board's decisions and orders are not subject to review by Cabinet.

In respect of its quasi-judicial duties the Board derives its mandate from numerous statutes, and from Orders in Council issued pursuant to the statutes. It is not subject to direction by individual Cabinet Ministers or members of the Legislative Assembly except through such legislation.

Appointments to the Board

The Lieutenant Governor in Council appoints the members of the Board and fixes their term of office. One member is appointed as Chairman of the Board and there is also provision for the appointment of a Vice Chairman. The members of the Board hold full time positions. At year end, there were seven members of the Board.

If additional members are required on a part time basis, the Chairman may name acting members, to act for any period of time or on any matter, from a list of potential acting members nominated by the Lieutenant Governor in Council. No acting members were required in 1989. At year end, the following three persons were available to be named by the Chairman:

K. J. Boyd
B. O. Archibald
J. Eugene Sekora

The Full Time Members and the Secretary

Ammon O. Ackroyd, Q.C., was appointed Chairman of the Board on March 1, 1984. He holds Bachelor of Education, Master of Education and Bachelor of Law degrees from the University of Alberta, and has been a teacher and a part-time lecturer at the University of Alberta. Prior to his appointment to the Board, he was the senior partner of the law firm of Ackroyd, Bradley & Associates. In addition to his responsibilities with the Public Utilities Board, Mr. Ackroyd is also Chairman of the Land Compensation Board, and Chairman of the Ministerial Committee on Telecommunications.

Anwar Jah was appointed a member of the Board on May 1, 1977. He has a Bachelor of Arts degree in Economics from the University of Karachi, has passed his British Institute of Bankers examination, and is qualified as a Certified Management Accountant. Prior to his appointment to the Board he was the Director of Rebates under the Alberta Natural Gas Rebates Plan. Mr. Jah also serves as a member of the Land Compensation Board and of the Ministerial Committee on Telecommunications.

A. Calista Barfett was appointed to the Board on September 15, 1982. She has taken numerous certificate courses at the University of Alberta, including Public Administration, Administrative Law and Accounting. Her background is in public administration, management and finance, having served in these capacities with both the Government of Alberta and municipal institutions. While involved in municipal government, she was responsible for municipal utilities, including natural gas utilities which appeared before the Board.

T. Donald Hetherington, Q.C., was appointed to the Board on November 1, 1982. He received his Bachelor of Science and Bachelor of Law degrees from the University of Alberta. Prior to his appointment to the Board, he engaged in the general practice of law with the firm of Ghitter & Company in Calgary. Mr. Hetherington is also a member of the Ministerial Committee on Telecommunications.

Neil W. MacDonald was appointed a member of the Board on December 5, 1984. He holds a Bachelor of Science degree in Electrical Engineering fr the University of Alberta. He has worked for a telecommunications utility in the areas of engineering design, inventory and valuation, division of revenue, depreciation and costs, and prior to his appointment to the Board was involved in the regulation of utilities as the Board's Technical Services Director. Mr. MacDonald also serves as a member of the Ministerial Committee on Telecommunications.

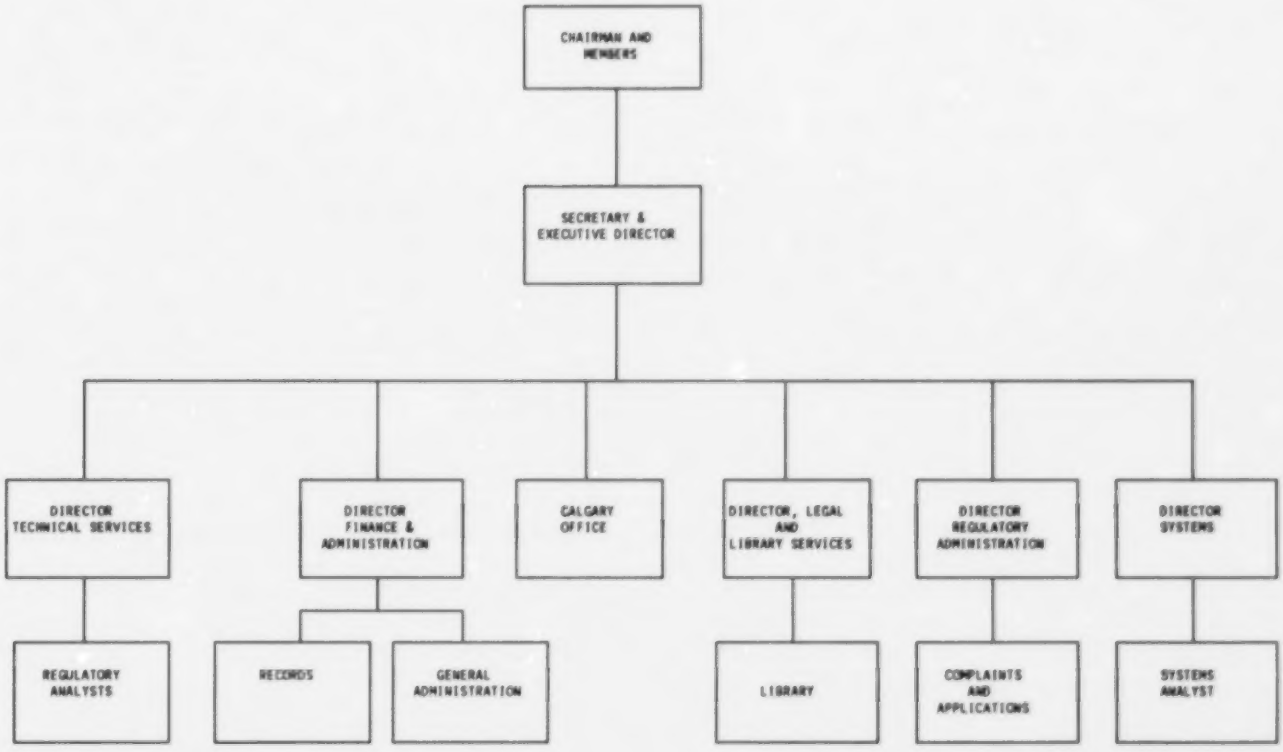
Robert D.S. Ward was appointed to the Board on April 15, 1987. He is a retired member of the R.C.M.P., and prior to joining the Board he was a businessman, commercial air pilot, a business consultant to the oil industry, and Chairman of Alberta Terminals Ltd. He also has been a member of other boards and agencies, including the Liquor Control Board of the N.W.T., the N.W.T. Highway Transport Board and the Alberta Surface Rights Board.

James R. Dunstan was appointed to the Board on June 1, 1987. Before joining the Board, he served as Chairman of the Alberta Electric Energy Marketing Agency from 1984 to 1987. He is a past President of the Lethbridge Chamber of Commerce and was Treasurer of the Alberta Chamber of Commerce. He has also been actively involved in community work, and was an alderman with the City of Lethbridge for two terms.

William Paterson was appointed Secretary and Executive Director in July, 1985. He is a Chartered Accountant having obtained his designation in Scotland in 1972 and in Canada in 1975. He joined the staff of the Board in 1977 and held a number of regulatory and management positions with the Board before his current appointment.

The Staff

At year end the Board had 44 authorized permanent staff positions. Reporting to the Secretary and Executive Director, the staff is organized into six main functional groups, as shown on the following organizational chart. The Technical Services Division is responsible for the provision of technical support to the Board in the fields of accounting, engineering, and economics. The Regulatory Administration Division responds to public inquiries and complaints, and deals with applications of a non-technical nature. The Finance and Administration Division is responsible for internal financial matters, personnel and records. The operation of the Board's electronic data processing facilities is the responsibility of the Systems Division. The Board also maintains a small secretarial and administrative section in Calgary. In addition, the Board has an in-house legal counsel.



The Board's Offices

The Board's Offices are located in:

Edmonton

11th Floor
10055-106 Street
Edmonton, Alberta
T5J 2Y2

Phone: (403) 427-4901
Fax: (403) 427-6970

Calgary

10th Floor
Energy Resources Building
640-5th Avenue S.W.
Calgary, Alberta
T2P 0M6
Phone: (403) 297-6306
Fax: (403) 297-6104

The Board's Finances

With respect to budgetary and administrative matters, the Board reports to the Lieutenant Governor in Council through the Attorney General and currently obtains all its revenues from the General Revenue Fund. For this purpose, the Board operates on a fiscal year beginning on April 1 and ending on March 31 and submits an annual budget for approval by the Alberta Legislature. It is difficult for the Board to precisely forecast its supply and services expenditures in any given year, as these are directly related to the number, type, length and complexity of the public hearings which the Board must convene. However, as of December 31, 1989, the Board was within its total budget and did not expect any over-run at fiscal year end, as shown by the table following this section.

Expenditure Control Group	1988/89 Budget	1988/89 Expenditures (Actual)	1989/90 Budget	1989/90* Expenditures (Forecast)
1. Manpower	$2,288,180	$2,250,662	$2,366,000	$2,346,000
2. Supplies & Services	273,820	264,192	309,800	289,000
3. Fixed Assets	229,000	228,951	215,000	215,000
TOTAL	$2,791,000	$2,743,805	$2,890,800	$2,850,000

* These amounts reflect actual expenditures for the period April 1, 1989 to December 31, 1989 plus estimated expenditures for the period January 1, 1990 to March 31, 1990.

Public Utility Regulation

1. Telecommunications Utilities

There are two telecommunications utilities within Alberta: city owned 'edmonton telephones' which serves the City of Edmonton, and Alberta Government Telephones (AGT), an Alberta Crown Corporation, which serves the remainder of the province.

In the past, the Board has been responsible for the regulation of AGT, but not for 'edmonton telephones'. However, on August 14, 1989, the Supreme Court of Canada, in an action commenced by AGT against the Canadian Radio-television and Telecommunications Commission and CNCP Telecommunications, ruled that AGT is an interprovincial undertaking and accordingly beyond the jurisdiction of the Board. In accordance with this ruling, the Board ceased all regulatory activity respecting AGT as of that date. This meant that the rate proceedings for AGT's 1988, 1989 and 1990 test years were cancelled.

However, certain members of the Board have subsequently been appointed to the Ministerial Committee on Telecommunications. This Committee is to act in an advisory capacity to the Minister of Technology, Research and Telecommunications. It will assist the Minister in ensuring that the services offered by AGT are provided in a manner consistent with the public interest on all issues relating to the definition and changes to the definition of basic and non-basic telecommunications services; the introduction of new basic services or changes to existing basic services; the establishment of new or changes to existing basic service rates; and the disposition of inquiries and complaints received from the public related to the services provided by the Commission.

For details respecting telecommunications applications which were processed by the Board prior to August 14, 1989, please see Section 1 of Appendix 1.

2. Electric Utilities

There are two major investor-owned electric utilities under the full jurisdiction of the Board. TransAlta Utilities Corporation, which operates primarily in the southern and central areas of the province, serves customers both directly and indirectly through wholesale contracts with municipally-owned distribution systems. Alberta Power Limited serves customers in the northern and eastern portions of Alberta. Border Power Ltd., a small investor-owned utility which serves approximately 200 customers in the Village of Coutts, is also under full Board jurisdiction.

The City of Edmonton owns and operates a fully integrated electric utility, Edmonton Power, which serves customers within its corporate limits. Pursuant to the Electric Energy Marketing Act, the Board is responsible for setting the price at which the City sells electric energy to the Electric Energy Marketing Agency, but does not establish end customer rates.

The Board dealt with a heavy slate of electric rate proceedings in 1989. Both TransAlta and Alberta Power were before the Board requesting approval of increases of approximately 7% in the average level of consumer rates in 1990. In its Phase I Decisions for TransAlta and Alberta Power, both issued December 15, 1989, the Board concluded that existing rates would provide a fair return to shareholders in 1990 while enabling the utilities to maintain existing service levels. The Board also directed TransAlta to refund excess revenues earned in 1988 and 1989 in the amount of some $100 million commencing in 1990. Phase II hearings, to determine whether or not it is necessary to restructure rates among different customer classes, will be held in 1990.

Full details respecting electric applications before the Board in 1989 are contained in Section 2 of Appendix 1.

3. Water Utilities

The vast majority of water utilities in Alberta are municipally-owned, and hence not subject to the full jurisdiction of the Board. However, in 1989 the Board held proceedings respecting a small investor-owned water utility operating in part of the County of Parkland. Several complaints were received by the Board concerning the rates and charges Acheson Park Water Corporation (Acheson Park) was levying to its customers for water usage. This application was in process at year end. More details of this application are contained in Section 4 of Appendix 1.

4. Natural Gas Utilities

There are nine investor-owned natural gas utilities which operate within Alberta, in addition to a larger number of municipally and cooperatively owned natural gas utilities which do not fall under the full jurisdiction of the Board. The three major utilities regulated by the Board are Northwestern Utilities Limited (NUL), which operates primarily in the northern and central areas of the province; Canadian Western Natural Gas Company Limited (CWNG), which operates primarily in the south; and ICG Utilities (Alberta) Ltd. (ICG) which distributes natural gas to a number of smaller communities throughout the province.

Energy pricing has been an important issue in the natural gas field since the deregulation of natural gas pricing occurred in November of 1986. Both CWNG and NUL obtain a substantial portion of their gas requirements under long term contracts with producers. During 1987 these companies renegotiated their gas supply contracts with producers on the basis of a two-tiered pricing system of $1.90 per gigajoule in the winter months and $1.40 per gigajoule in the summer months. Negotiations with some of these producers respecting prices to be effective November 1, 1988 remained in progress at the end of 1989.

Transportation of natural gas also remained a significant issue in 1989. During the year, the Board approved the introduction of certain additional gas transportation services and rates. In Decision E89038 dated May 3, 1989, three different "interruptible" gas transportation rates were approved, in consideration of the fact that the CWNG/NUL gas systems are operating at near full capacity. Further, in Decision E89101 dated October 25, 1989, the Board approved two new transportation rates on an interim basis. Rate 12 is available to industrial customers of CWNG/NUL who presently use the Optional General Service sales rate, and Rate 41 is the expanded version of the existing Buy-Sell Rate 40, which is still available under the approved rate schedules of CWNG/NUL. The Board expects to hold a hearing respecting these interim rates early in 1990.

NUL's most recent general rate application respecting the 1987 and 1988 test years was finalized by the Board in 1989. The Board's Phase II Decision E89001 dated February 3, 1989 examined the issues of rate design, cost of service studies, and utility terms and conditions of service. Such determinations are necessary to establish just and reasonable rates, tolls and charges, and service regulations. Final rates were approved, effective May 1, 1989, in Decision E89035 to recover on an annualized basis the 1988 revenue requirement.

CWNG was also before the Board in 1989. On June 21, 1989, the City of Calgary filed an application requesting that the Board hold a hearing into the rates, tolls or charges for natural gas service provided by CWNG for 1989 and

thereafter. Calgary's evidence showed that from 1986 through 1988, CWNG had earned a return on shareholders' equity in excess of that approved by the Board in determining CWNG's 1986 test year revenue requirement, and that CWNG's 1989 first quarter earnings were higher than comparable earnings for 1988. Decision C89037 dated August 2, 1989, approved the application and ordered that CWNG file by November 1, 1989 complete particulars, information and data to enable the Board to fix just and reasonable rates for the 1989, 1990 and 1991 test years. Although the earning of such "excess return" by CWNG in prior years was not necessarily an indication that such would also occur in 1989, the Board considered that the absence of contrary evidence from CWNG was some indication that CWNG anticipated returns higher than those which the Board could be expected to allow for 1989. The Board also noted that there had been a great number of regulatory and other changes to CWNG's operating environment since its last general rate application, each of which would affect CWNG's future earnings.

Consequently, the Company applied on November 1, 1989 for approval of a change in rates for the 1989, 1990 and 1991 test years. In addition, ICG applied on November 23, 1989 for approval of a change in rates for the 1989 and 1990 test years. Both these applications were in progress at year end.

Details of these and all other natural gas applications are contained in Section 5 of Appendix 1.

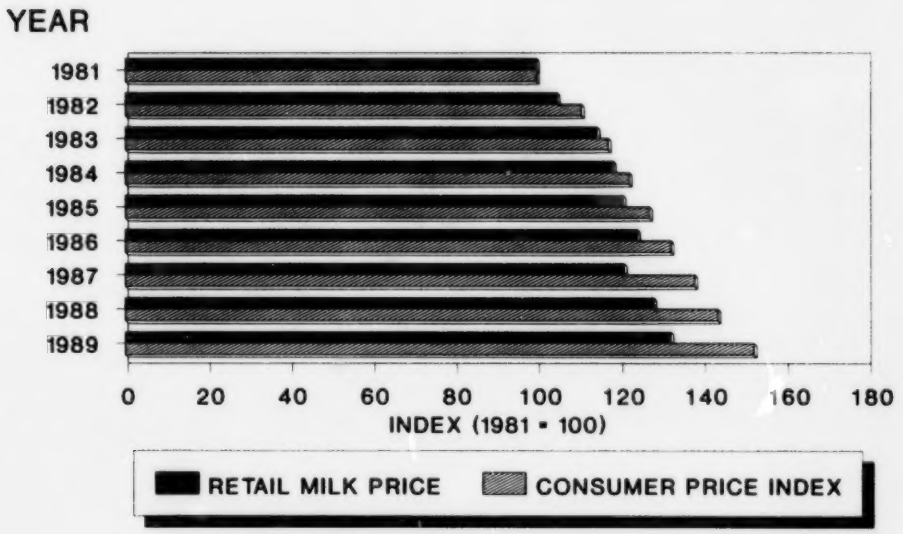
5. Comparing Increases in Utility Rates with Inflation

The following graphs indicate how increases in Alberta's electrical, natural gas and telecommunications rates and minimum milk prices compare with increases in the Canadian Price Index (CPI) from 1981 to 1989. However, due to the significant and continuing impact of the Electric Energy Marketing Act, the electric graph commences in 1982, the year this Act became effective. The figures have been calculated by Board staff assuming annual residential consumption levels of 6000 kWh for electricity and 227 GJ for natural gas. The telecommunications graph uses fixed monthly rates for residential customers in Calgary.

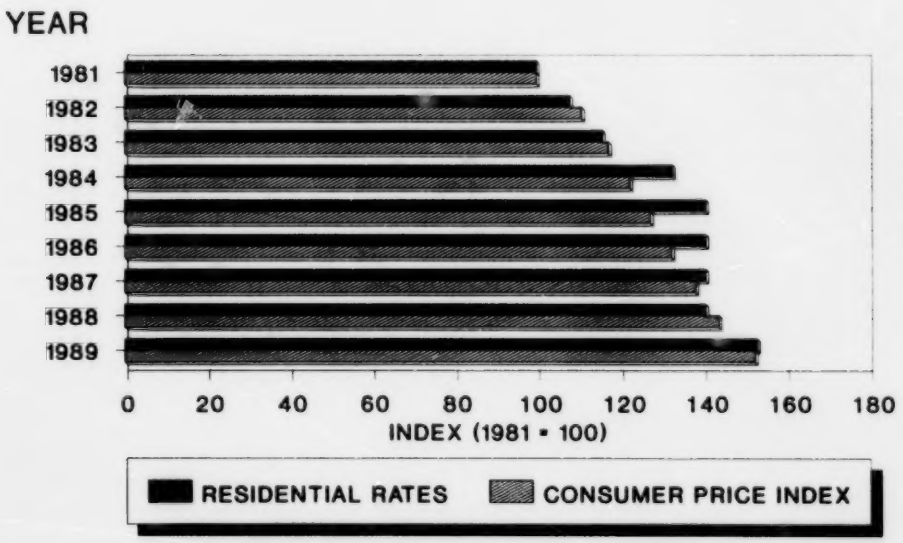
Currently, most utilities' indexed rate increases are at or below the CPI. As discussed more fully later in this report, in addition to its ratemaking function for public and gas utilities, the Board also prescribes the minimum price of fluid milk and fluid milk products. It should be noted that increases in minimum milk prices have consistently remained lower than increases in the CPI.

There are many reasons why increases in utility rates may sometimes be higher or lower than inflationary changes. It must be remembered that the utility industry is capital intensive, and hence greatly impacted by increases in interest rates. Furthermore, construction of new plant must be planned years in advance, and in some cases expenditures were made which were later called into question with the downturn in the economy. Natural gas rates throughout much of the 1980s were greatly increased by federal taxes, such as the Natural Gas and Gas Liquids Tax, the Canadian Ownership Special Charge and the Petroleum and Gas Revenue Tax. There was also the impact of federal-provincial pricing arrangements which set natural gas costs up until November of 1986. It must be noted that natural gas costs constitute roughly 60% of an annual bill, costs which have been largely beyond the control of the utilities and the Board.

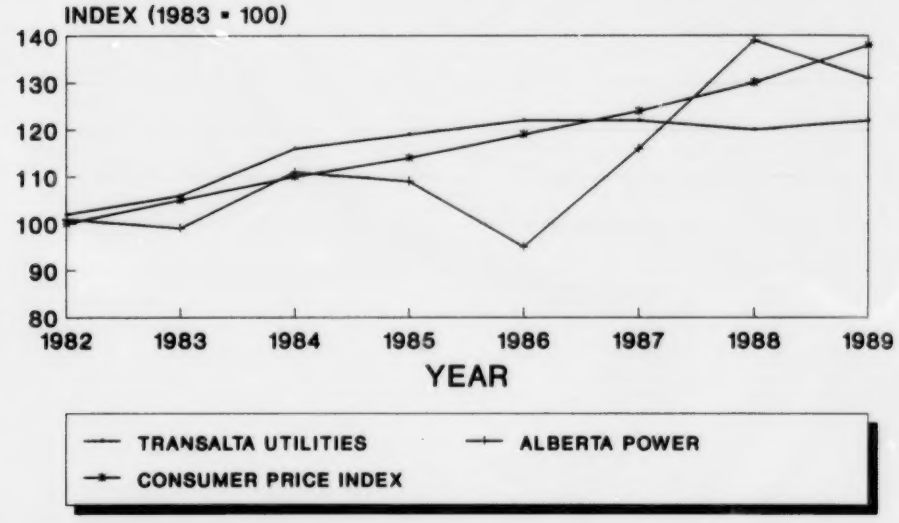
MINIMUM RETAIL MILK PRICES VERSUS THE CONSUMER PRICE INDEX



ALBERTA GOVERNMENT TELEPHONES VERSUS THE CONSUMER PRICE INDEX

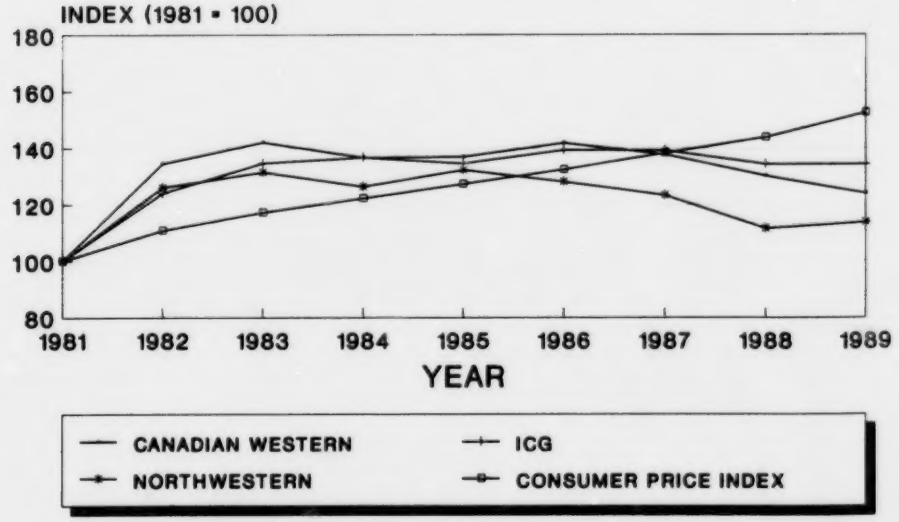


REGULATED ELECTRIC RATES
VERSUS THE CONSUMER PRICE INDEX



BASE SET AT $400 = 100

REGULATED NATURAL GAS RATES
VERSUS THE CONSUMER PRICE INDEX



Public Participation

Public involvement is crucial to the effective operation of the regulatory process. The Board welcomes all constructive input respecting utility rates and terms and conditions of service.

In general rate applications, the Board benefits from interventions by different groups or members of the public which assist it in testing the applicant's case. To ensure the fullest possible public participation, the Board directs the applicant to publish notice of the proceedings in newspapers throughout the utility's service area, and to serve the notice on municipalities, public interest groups or other parties who have made their interest known to the Board.

Members of the Board's staff are assigned to each application before the Board, and the staff are available to answer any questions from the public or to assist parties with organizing their interventions. In addition, the Board has published brochures entitled "The Ratemaking Process" and "How to Intervene" to outline the relevant procedures to interested parties. These brochures are available free of charge from the Board's offices.

To further facilitate public participation, the Board may order that the applicant pay the intervenors' expenses. Section 60 of the Public Utilities Board Act provides the Board with discretionary authority to order that the costs incurred in connection with a rate application should be paid for by the utility and recovered through customer rates. This practice serves to encourage public interventions in the absence of other forms of public input, such as a consumer advocate. However, the Act does not allow the Board to provide advance funding for any party considering intervention.

The Board recognizes that intervention, which is aimed at reducing utility rate increases, is paradoxically expensive and adds to the customer's utility bill. Therefore, before exercising its discretion to award costs, the Board considers a number of questions, such as the effectiveness of the intervention, its relevancy to the issues, and whether the costs of the intervention were necessary and reasonable. Those who have a common interest in the proceedings are encouraged to co-ordinate their presentations so as to avoid duplication of effort and thereby minimize costs. Applications for costs are considered after the completion of the hearing process.

Moreover, in 1989 the Board took further steps to deal with the rapid escalation in hearing costs. By resolution of the Board on May 24, 1989, a scale of costs was adopted. The scale sets a cap on professional fees which will normally be awarded by the Board, and outlines those disbursements which will be considered for reimbursement. A copy of the Scale of Costs is included as Appendix 5 to this Report.

During the course of the year, the Board granted costs awards in connection with many rate applications. Interventions were lodged by a variety of parties, including municipalities, institutional groups, consumer associations, and individual customers. While cost orders respecting a number of 1989 proceedings were pending at year end, the Board in 1989 awarded intervenors' costs of $2,350,996. In addition the Board awarded applicant external costs in the amount of $1,120,536.

Procedural Review Report

The Board is constantly striving to improve the conduct of hearings, and to make these accessible to the public. Accordingly, in 1988, the Board commenced a review of its practices and procedures, to ensure that these were as fair, open and efficient as possible. All regular participants in Board proceedings were invited to

prepare submissions on the four issues of concern to the Board, namely its rules of practice, costs awards, the use of plain language and the hearing process. The Board's report on these issues was released on June 30, 1989. Copies of the Procedural Review Report are available free of charge through the Board's offices. Highlighted below are the major findings contained in this report.

1. Rules of Practice

The Board concluded that detailed rules of practice were unnecessary in light of the procedural requirements contained in numerous statutes, including the Administrative Procedures Act. The Board's procedures are also in part dictated by the duty to be fair as set out in numerous judicial decisions. However, the Board recognized that parties to a proceeding may require general guidance as to the Board's practices. Consequently, the Board developed a set of guidelines to outline its procedures, which were included as an appendix to the Procedural Review Report.

2. Costs Awards

The Board noted that intervenors make an invaluable contribution to the hearing process. Nonetheless, as a result of the escalation in hearing costs, the Board adopted a scale of costs in 1989. As discussed earlier, this scale, which is in its embryonic stages, sets a cap on professional fees and prescribes allowable disbursements. The Board also has required the utilities to establish a PUB Hearing Costs Reserve Account to enable effective accounting of hearing costs. Another matter under Board consideration is the use of a taxing officer to examine costs claims.

3. Plain Language

Utility regulation is highly complex. To increase public understanding of this technical field, the Board prepared a glossary of utility terms, which was also attached as an appendix to the report. In addition, the Board expressed its intention to prepare an executive summary for all its orders and decisions. Utilities were also encouraged to continue their efforts to simplify bill formats.

4. The Hearing Process

The examination and determination of a general rate application is a lengthy exercise. To streamline the process, the Board stated that it would utilize such measures as the enhanced use of the pre-hearing conference to outline and prioritize issues and to establish time limits. A staff report, in an appropriate case, may also be used to increase efficiency. The Board expressed caution lest expediency diminish the quality of regulation. Therefore, it was the Board's intention to balance the objectives of timeliness and fairness through prudent management of the public hearing process.

Public Inquiries and Complaints

Public input is an important element in the Board's decision-making process. However, public participation is not limited to formal rate proceedings. The Board welcomes inquiries and complaints from the public respecting any aspect of utility service. A brochure entitled "Making a Complaint" is available from the Board's offices to assist in this process.

In 1989, Board staff received a total of 154 complaints by telephone and 44 written complaints, as well as a large number of general inquiries. The Board makes every effort to respond to inquiries and complaints in a prompt and informative manner. Telephone complaints may sometimes be resolved by the provision of information respecting utility rates or terms and conditions of service.

In other cases, the complainant may be referred to the utility company in question for further information. If the matter cannot be resolved by these means, the customer will be asked to submit a written complaint. Written complaints are usually investigated with the utility company, and occasionally a public hearing may be required to resolve the dispute.

Public hearings were held in 1989 respecting two written complaints submitted to the Board. These dealt with the topics of security deposits and discriminatory rates. Details respecting the formal written complaints which required consideration by members of the Board through the public hearing process are contained in Appendix 1 and are not included in the statistics in this section.

In addition to the public hearing process, in 1989 the Board on numerous occasions met informally with complainants and representatives of the utility companies involved to try to resolve disputes. In many cases, these forums allowed the parties the opportunity to arrive at a mutually satisfactory course of action, obviating the need for formal Board intervention.

Of the 44 non-registered written complaints dealt with by the Board, 19 dealt with billing disputes, and 3 concerned service problems. Billing disputes accounted for the most telephone complaints, with disconnection action, installation charges and rate increases being other frequent areas of concern. At year end, all of the complaints received by telephone were resolved, while two of the written complaints remained under investigation.

The following table contains a breakdown of the complaints received by the Board in 1989.

Type of Utility	Nature of Complaint	Written	Telephone
Telephone	Installation Charges	2	3
	Service Problems	3	5
	Rate Increases	1	6
	RILS	4	6
	Refund Method	-	7
	Rate Structure	-	4
	Miscellaneous	5	14
Electric	Billing Disputes	6	13
	Rate Structure	1	6
	Disconnection	-	6
	Installation Charges	1	4
	Miscellaneous	2	7
Natural Gas	Billing Disputes	7	12
	Security Deposits	-	7
	Disconnection	-	12
	Late Payment Penalty	1	3
	Miscellaneous	2	9
Other (Gas Co-ops, Municipalities, Milk, etc.)	Billing Disputes	6	18
	Disconnection	1	3
	Installation Charges	-	3
	Miscellaneous	2	6
TOTAL COMPLAINTS		44	154

Other Functions and Responsibilities

While rate-making is the most widely known activity of the Board, the Board performs a number of other important functions, some of which are described in detail below.

1. General Supervision of Utilities

The Board is required by statute to exercise a general supervision over utilities within its jurisdiction, and to ensure their compliance with the law. As part of the regulatory process, the Board is also responsible for reviewing the affairs, earnings and accounts of each owner of a public utility or gas utility within three years of fixing their rates. To ensure compliance with the mandatory review requirements, the Board selects utilities to be reviewed during a given year and authorizes technical staff analysts to proceed with the necessary inquiries.

The consideration of a utility's general rate application also provides an opportunity for the necessary review through the public hearing process, since a thorough examination of the utility's operations is required for the determination of a rate base and fair return. Consequently, the Board's review schedule is under constant revision as general rate applications are processed, thereby satisfying the formal review requirements.

A report on the review of the affairs, earnings and accounts of Southern Utilities Company Limited (now Border Power Ltd.) was issued in 1989. A review of Grande Prairie Transmission Co. Ltd. was in progress at year end.

2. Municipal Supply Contracts and Special Franchise Agreements

Pursuant to sections 279 and 280 of the Municipal Government Act, a municipality must obtain the approval of the Board to enter into a supply contract or a special franchise agreement with a public or gas utility. Renewals or alterations of such contracts must also receive Board approval, pursuant to section 281 of the Municipal Government Act.

A supply contract grants a utility company the right to provide utility services for distribution by the municipally owned utility system. A franchise agreement generally provides the utility company with the exclusive right to directly supply and serve customers within the specified franchise area.

Applications for approval of a franchise agreement often include applications for approval of a franchise tax. This requires the utility company to pay the municipality a percentage of the gross revenue of the utility realized within the municipality, in lieu of property tax. The level of the franchise tax varies between communities, but generally constitutes a significant component of the customers' bills. For example, the amount of this municipal franchise tax for gas utilities in Alberta's major cities is 10% of the gas bill including the franchise tax. Because of the impact on customers' bills, the Board requires the utility companies to show the amount of the franchise tax as a separate item on utility bills. In cases where the municipality applies to increase the level of the franchise tax which is paid by the utility, the Board requires the utility to print a notice to customers on the first occurrence of the rate increase, advising of the dollar impact of the change, and advising that the change in rates was at the request of the municipality.

During 1989, the Board heard a number of supply contract and special franchise applications, as outlined in Section 7 of Appendix 1. To facilitate consumer representation, in 1989 many of these hearings were conducted in the municipalities involved.

3. Milk Prices

Under the Dairy Board Act, the Board is required to set the minimum price of fluid milk that may be paid to producers, and the minimum wholesale and retail prices of fluid milk and fluid milk products that may be charged by processors, distributors and sellers. It is important to note that these are MINIMUM prices.

Since 1976, the Board has used the fluid milk pricing formula, developed with the assistance of the Production Economics Branch of the Alberta Agriculture Department, to help determine the minimum price of milk. In Decision E76104 dated August 13, 1976, the Board stated:

> "The Board will continue to use formula pricing as a guide in fixing the minimum price to be paid to producers for Class 1 fluid milk.
>
> The Board reserves the right to adjust or not to adjust the minimum producer price as indicated by the formula price if it finds that unusual circumstances prevail at any particular time. The performance and results of formula pricing will be monitored continuously, tested against the production cost study annually and reviewed at public hearings periodically in response to an application or upon the Board's own initiative."

This formula was reviewed by the Board in 1989, who concluded that it remained a viable pricing indicator. Certain changes in the minimum producer prices of milk were approved in 1989 as a result of the application of this fluid milk pricing formula. There were increases of one cent per litre in the minimum wholesale and retail prices of fluid milk products, effective April 1, 1989 and August 7, 1989, and a decrease of one cent per litre in the minimum prices effective November 3, 1989.

In addition to reviewing applications resulting from milk pricing formula changes, the Board also rendered an interim decision in 1989 respecting an application received from certain Processors/Distributors for approval of an increase in the minimum price of fluid milk and milk products, and for a price differential for milk sold in plastic jugs. In their interim application, the Processors/Distributors requested an increase of three cents per litre effective November 1, 1989 and a further increase of two cents per litre effective January 1, 1990. Order E89109 dated December 6, 1989 approved an interim increase of only one cent per litre in the minimum wholesale and retail prices for fluid milk products, pending the Board's full investigation of the application.

Orders resulting from the Board's milk pricing activities are summarized in Section 10 of Appendix 1.

4. Duties Pursuant to the Electric Energy Marketing Act

The Board is required pursuant to the Electric Energy Marketing Act to set the price or the pricing formula, for each consumer group, at which electric energy will be sold to the Electric Energy Marketing Agency.

The Electric Energy Marketing Act, which became effective September 1, 1982, requires TransAlta Utilities Corporation, Alberta Power Limited and Edmonton Power to sell all the electric energy generated by these utilities, for consumption within Alberta, to the Electric Energy Marketing Agency at prices established by the Board. These prices are based upon the cost of generating and transmitting electric energy to the designated pooling interface points. The Agency pools these costs and resells the electric energy to the three utilities at an average price. To the extent that this process averages generation and transmission costs there is a

measure of equalization of costs throughout Alberta, but the exclusion of distribution costs results in some variations in rates for customers in different areas.

Currently, both TransAlta and Edmonton Power pay more to repurchase electric energy from the Agency than their selling price. This has resulted in increases in the cost of electric energy to customers served by those utilities. To ease the impact of these increases, the Alberta Government established a shielding program, which gradually phased the rate equalization procedure into consumer rates in Southern Alberta and Edmonton. This shielding program came to an end during 1989.

On February 15, 1989, the Board rendered its decision respecting the prices at which Alberta Power, TransAlta and Edmonton Power would sell electric energy to the Electric Energy Marketing Agency for the year 1989. In its Decision E89004, the Board determined that Edmonton Power's Genesee 2 power plant was not required to be used in 1989 and therefore excluded this plant from Edmonton Power's 1989 costs to the Agency. Similarly, the Board excluded the cost of a significant transmission system, namely the SPC-DC tie interconnection between Saskatchewan and Alberta which is owned by APL, from upstream rate base, in addition to a major portion of the costs of TransAlta's Keephills/Ellerslie transmission system, following its determination that these were not required to be used in 1989. Decision E89004 was appealed to the Court of Appeal in 1989, by each of Alberta Power, TransAlta and Edmonton Power. The Court's decision was pending at year end.

Proceedings were also held in 1989 to determine the prices at which Alberta Power, TransAlta and Edmonton Power would sell electric energy to the Electric Energy Marketing Agency during 1990. In 1991 the Board may adjust these prices to reflect the utilities' actual costs. In its Decision E89097, the Board allowed the inclusion of the costs of the first completed unit of Edmonton Power's Genesee power plant in the 1990 price to the Agency, but excluded the costs in 1990 of the second unit of the Sheerness power plant, which is jointly owned by TransAlta and Alberta Power.

Further details respecting Electric Energy Marketing Agency applications are contained in Section 3 of Appendix 1.

5. Municipally-Owned Utilities

Municipally-owned utilities are not subject to the full jurisdiction of the Board, unless they pass a by-law submitting the operation of their utilities to the control and orders of the Board. At present, no municipalities are under the full jurisdiction of the Board. However, pursuant to Section 291 of the Municipal Government Act, a user of a municipally-owned utility (with the exception of 'edmonton telephones'), may lodge a complaint with the Board alleging that the rates of the utility do not conform to the rate structure established by the municipality; have been improperly imposed; or are discriminatory. If the Board concurs it may vary or disallow these charges.

In 1989, the Board received a number of complaints pursuant to this section. For example, the Board received a complaint from the owners of a mobile home park in the Town of Bashaw, alleging that the Town's sewer rates to the mobile home park were discriminatory. The Board held a hearing in the Town of Bashaw to examine this complaint, and concluded that the charges were indeed discriminatory. It was noted that the owners were billed differently from all other sewer customers, and no recognition was made of the additional costs borne by

the complainants, who own and maintain their own sewer line and pump. Consequently, the Town was directed to commence billing the mobile home park on the same basis as all the other customers of the sewer system. Further details of complaints respecting municipally-owned utilities are contained in Section 7D of Appendix 1.

In addition, the Board hears and determines disputes with respect to the rates charged for utility services provided by one municipality to another municipality. No such applications were received in 1989.

6. Rural Gas Utilities

Rural gas utilities are not subject to the jurisdiction of the Board, except where specifically provided in the Rural Gas Act. Section 37(1)(b) of this Act provides that the Board may hear and resolve complaints with respect to the rates imposed by rural gas utilities when it is alleged that such rates do not conform to the rate structure established by the utility; have been improperly imposed; or are discriminatory.

Furthermore, the Board sits as an appellate tribunal with respect to disputes over service area boundary decisions made by the Chief Officer as defined in the Rural Gas Act. No such applications were received in 1989.

7. Intra-Provincial Railways

The definition of a public utility contained in the Public Utilities Board Act includes a system which conveys travellers or goods over a railway. Such systems are required to file rates with the Board and such rates cannot be changed without Board approval. In the past year, Central Western Railway (CWR) has filed its rates with the Board. However, the Federal Court of Appeal has found CWR to be a federal undertaking, as it forms part of the national grain transportation network, and hence subject to federal regulation. This matter is in the process of being appealed to the Supreme Court of Canada. At year end, the Court had not yet heard the appeal.

In addition, Section 95 of the Public Utilities Board Act specifies that the permission of the Board must be obtained for the construction of highway crossings by a railway company within the legislative authority of Alberta, and that the Board shall make reasonable provisions for the protection of the travelling public with respect to these grade crossings. Such Board permission had been granted in 1988 in Order E88066, with respect to the construction of an "at grade railway crossing" in the Town of Peace River. In 1989, the Board approved an application for a review and variance of this order with respect to one of the Board directed safety specifications during the construction period when rail traffic was limited, having concluded that the protection of the travelling public was being otherwise adequately insured.

8. NOVA Corporation of Alberta

The Board hears and resolves complaints with respect to the rates charged by NOVA Corporation of Alberta for the transportation of gas within Alberta. Section 37(2) of the NOVA Corporation of Alberta Act provides that, upon complaint in writing of an interested party, the Board is responsible for determining the justness and reasonableness of the rates, tolls or other charges fixed or varied by NOVA, and by order in writing may vary or confirm the foregoing rates, tolls or other charges. No such complaints were received by the Board in 1989.

9. Compensation Fixing Duties

A number of statutes confer compensation fixing duties upon the Board. For example, the Board hears and determines disputes with respect to the payment of compensation which may be required when all or part of a franchise area of a rural gas utility is annexed to a municipality and becomes served by another utility. In addition, the Board may determine compensation respecting the sale of Rural Electrification Association assets. When directed by the Lieutenant Governor in Council, the Board may also fix compensation with respect to air pollution damage claims, water pollution damage claims and environment damage claims. No such applications were received by the Board in 1989.

10. Appeals of the Alberta Cost of Service

Under the Natural Gas Pricing Agreement Act and Regulations, the Board acted as an appellate tribunal with respect to determinations of the "Alberta Cost of Service" made by the Alberta Petroleum Marketing Commission prior to October 31, 1987 with respect to the transportation of gas within Alberta. The Board issued Decision E87113 dated October 30, 1987 with respect to an appeal by Husky Oil Limited of the "Alberta Cost of Service." The Board's decision was appealed to the Court of Appeal, whose decision, issued December 8, 1988 and received by the Board on January 9, 1989, upheld the decision of the Board.

Under the Natural Gas Marketing Act, the Board sits as an appellate tribunal for determinations of the "Alberta Cost of Service" made by the Alberta Petroleum Marketing Commission. No such appeals were received by the Board in 1989.

11. The Energy Resources Conservation Board Hearings

Order in Council 234/85 provides that certain members of the Board are nominated as persons who may be named as Acting Members of the Energy Resources Conservation Board (ERCB). No such Acting Member appointments were made in 1989.

12. Gas Processing Costs

Section 10 of the Gas Utilities Act states that, subject to the authorization of the Lieutenant Governor in Council, the Board may fix the costs, or method for ascertaining costs, for the gathering, treating or processing of gas. In 1988, Mr. Frederick Haller made an application to the Board pursuant to this section requesting the Board to determine the costs, or the method for ascertaining costs, for gas derived from lands owned by Mr. Haller and produced and processed by Gulf Canada Resources Limited. This matter was resolved by the parties and the application to the Board was withdrawn by Mr. Haller in April of 1989. Certain further applications pursuant to this Section were received by the Board towards the end of the year, and were under Board consideration.

13. Inquiries

From time to time the Board, on its own initiative or at the request of the Lieutenant Governor in Council, may hold public inquiries into matters of topical concern which fall within its jurisdiction. No such inquiries were held in 1989.

Summary of Regulatory Activity

1989

This table provides some selected statistics which describe the volume of regulatory activity during 1989 in the same categories used in Appendix 1, "Applications to the Board".

	APPLICATIONS CARRIED FORWARD FROM 1988	APPLICATIONS RECEIVED DURING 1989	TOTAL APPLICATIONS TO BE DEALT WITH IN 1989	APPLICATIONS FINALIZED BY BOARD ORDERS OR DECISIONS	APPLICATIONS FINALIZED WITHOUT BOARD ORDERS OR DECISIONS	TOTAL APPLICATIONS FINALIZED IN 1989	APPLICATIONS CARRIED FORWARD TO 1990	DAYS OF FORMAL HEARINGS	DAYS OF IN-OFFICE HEARINGS
1. Telecommunications Utilities	2	8	10	5	5	10	0	4	0
2. Electric Utilities	2	13	15	9	1	10	5	21	1
3. Electric Energy Marketing Act Proceedings	2	9	11	2	0	2	9	12	0
4. Water Utilities	1	0	1	0	0	0	1	2	0
5. Natural Gas Utilities	12	22	34	27	1	28	6	10	6
6. Utilities not offering utility services to the general public	0	9	9	9	0	9	0	0	6
7. Municipalities									
7A. Special Franchise Agreements (the Municipal Government Act)	12	82	94	77	1	78	16	1	29
7B. Supply Contracts (the Municipal Government Act)	0	2	2	2	0	2	0	2	0
7C. Supply and Lighting Agreements (the Improvement Districts Act)	0	0	0	0	0	0	0	0	0
7D. Complaints (the Municipal Government Act)	0	1	1	1	0	1	0	1	0
7E. Other Applications	1	0	1	0	0	0	1	1	0
8. Complaints Under the NOVA Corporation of Alberta Act	0	0	0	0	0	0	0	0	0
9. Appeals Under the Natural Gas Marketing Act	0	0	0	0	0	0	0	0	0
10. Milk Pricing	0	5	5	3	1	4	1	1	0
11. Other Matters	1	4	5	1	2	3	2	0	0
Totals	**33**	**155[1]**	**188**	**136[2]**	**11[3]**	**147**	**41[4]**	**55**	**42**

[1] Includes cases where the Board acted on its own motion and matters which were referred back to the Board by the Courts.

[2] In 1989, 119 Orders and Decisions were issued by the Board. In 1988 there were 133 Orders and Decisions issued.

[3] Includes applications withdrawn by the applicant.

[4] Some applications reflected have been partially dealt with by Board Orders and Decisions but are not yet finalized.

Appendix 1

Applications to the Board

Section 1: Telecommunications Utilities

Data reported in groups arranged alphabetically according to the name of the regulated utility to which the application refers. Individual applications within each group are then arranged in order of registration number.

ITEM NUMBER
APPLICATION PARTICULARS
(a) REGULATED ENTITY/REGISTRATION NUMBER/FILE NUMBER
(b) SUBJECT MATTER
(c) DISPOSITION/REFERENCE

1.01 (a) **Alberta Government Telephones**
RC86007 / E3.4.89-73
(b) Application by the City of Calgary for approval of a change in the rates, tolls and charges of Alberta Government Telephones (AGT).
(c) Application was withdrawn by letter dated January 18, 1989.

1.02 (a) **Alberta Government Telephones**
RE86085 / E3.4.89-75B
(b) For approval to change its rates, tolls or charges for the 1986 and 1987 test years.
(c) (1) Phase II Decision E88089 dated December 23, 1988 approved final rates for the test year 1987.

(2) Order E89006 dated January 23, 1989, amended Decision E88089, at the applicant's request, by deleting the direction to add Nordegg to the Isolated Community Calling service, by extending the time limit for filing rates for the Basic portion of CENTRON services and extending the time limit for making a final refund of its surpluses from 1986 and 1987.

(3) Order E89024 dated March 31, 1989, amended Order E89006 dated January 23, 1989, by extending the date for filing the CENTRON basic tariff to May 1, 1989. The Board was satisfied that the effects on AGT's revenues or the cost and quality of service to customers would be minimally affected by this change in filing date.

(4) Order E89034 dated May 8, 1989, fixed costs arising from AGT's Interim and Phase II Proceedings. The Board determined that Intervenors' costs payable by AGT were $154,089.53. The amounts claimed were $234,820.26. The Board determined and fixed AGT's external costs at $72,487.68. The amount claimed was $92,856.03.

1.03 (a) **Alberta Government Telephones**
RE89007 / E3.4.89-75B R.V.
(b) For a review and variance of Board Decision E88089 dated December 23, 1988 which, at page 93, directed AGT to retain Foreign Exchange, Off - Premises Extensions and Tie Trunks (voice private lines) on the Basic tariff.
(c) Decision E89012 dated March 3, 1989, approved AGT's proposal to place voice private lines on the Non Basic Tariff. AGT had submitted that Section 25 of the Telecommunications Act gave it the exclusive right to provide basic services in Alberta. This effectively prevented other carriers from supplying these private lines under the Systems Interconnection tariff, also approved in Decision E88089. The Board agreed that the term "Basic" had the same usage in the Telecommunications Act as for the Board's regulatory purposes. The Board, upon hearing evidence from CNCP Telecommunications and AGT, was satisfied that a competitive situation would exist for these voice private line services and that, since there would no longer be a need to price regulate them, the proper conditions existed to declare them Non Basic.

1.04 (a) **Alberta Government Telephones**
RE89010 / E3.4.89-75B R.V. (2)
(b) Application by Regional Maple-Leaf Communications (RMC) for a review and variance of Decision E88089 dated December 23, 1988 with respect to the decision made by the Board at page 73 with respect to timing increments for Wide Area Telephone Service (WATS). Decision E88089 directed AGT to make the timing increment six seconds on WATS 120 service but not WATS 10.
(c) Decision E89015 dated March 3, 1989 provided the Board's reasons for denying the application for review and variance. After a careful reading of the applicant's evidence presented at AGT's Phase II hearing, the Board found nothing which specifically directed the Board's mind to the premise that the applicant was applying for six second timing not only on WATS 120 but on WATS 10 as well.

1.05 (a) **Alberta Government Telephones**
RE89012 / E3.4.89-80
(b) For approval to change the terms and conditions of service for Public Cellular Mobile Radio Systems - Network Access.
(c) Order E89010 dated February 16, 1989, approved AGT's proposal to change its terms and conditions of service contained in its General Tariff - Basic Services at Item 315.3. Decision E88089 dated December 23, 1988 approved terms and conditions which provided that each Cellular System Operator (CSO) would be provided a unique NXX code (first three numbers of a telephone number). Subsequently, AGT found that the limited number of NXX codes available meant that in all cases CSO's could not have unique NXX's. AGT proposed that CSO's share NXX codes but be assigned a block of 1000 numbers within that NXX. The Board approved AGT's proposal under Section 50(1) of the Public Utilities Board Act as service was urgently required by the only customer affected by the proposal.

1.06 (a) **Alberta Government Telephones**
RE89013 / E3.4.89-81
(b) For an Order amending AGT's General Tariff - Basic Services with respect to Private Mobile Telephone System - Network Access.
(c) Order E89013 dated February 28, 1989, amended Decision E88089 by deleting the local channel charge for central office connection. Decision E88089, at page 110, approved AGT's proposals with respect to private mobile system interconnection, which included the local channel charge. The Board was satisfied that

Appendix 1

it was not AGT's original intention to impose this charge and that AGT's proposal in Filing 89-07 would result in a lower monthly rate to customers. Also, it would be costly to modify AGT's billing system in order to collect the charge.

1.07 (a) **Alberta Government Telephones**
RE89046 / E3.4.89-82
(b) For approval of a change in rates for the test years 1988, 1989 and 1990.
(c) The proceedings were discontinued as of August 14, 1989, as a result of the decision of the Supreme Court of Canada, which is more fully set out in the text of the report.

1.08 (a) **Alberta Government Telephones**
RE89050 / E3.4.87(1)(g)-7
(b) For approval of the sale of telecommunications business, plant and real property on the Saskatchewan side of the City of Lloydminster.
(c) Order C89032 dated July 24, 1989, approved the sale.

By letter dated June 19, 1989, AGT filed an application for an Order of the Board approving, effective the transfer date of July 10, 1989, the sale of telecommunication business, plant and real property on the Saskatchewan side of the City of Lloydminster as set out in the Agreement for Sale between AGT and Saskatchewan Telecommunications (Sask Tel) pursuant to Section 91.1(2)(d) of the Public Utilities Board Act.

At the request of Sask Tel, AGT agreed to sell all of its telecommunication business, plant and property located on the Saskatchewan side of the Alberta/Saskatchewan border, at reproduction cost new less accumulated depreciation, subject to the approval of the Board, to enable Sask Tel to provide telephone service to all of those residents within the Province of Saskatchewan.

Sask Tel agreed to pay $3,255,000 to AGT on the transfer date as an initial payment for the plant and equipment, pending determination of the final price. Sask Tel further agreed to pay an additional $1,440,000 to AGT in 36 monthly installments of $40,000 each as full and final payment for AGT's costs, miscellaneous sale items and lost revenues or goodwill.

The sale resulted in an estimated net gain of $3,024,000, which AGT indicated was included in the General Rate Application in Utility Revenue.

The Board determined that the sale of AGT's telecommunication plant and assets in the Province of Saskatchewan to Sask Tel would not adversely affect the interests of customers of AGT in the Province of Alberta.

Consequently, the Board approved the sale as described in the application on the provision that the actual accounting treatment of the matter be dealt with at the time of the 1988/89/90 AGT General Rate Application.

1.09 (a) **Alberta Government Telephones**
RE89055 / E3.4.89-75A R.V.
(b) For a review and variance of Board Decision E88004 dated February 19, 1988.
(c) The proceedings were discontinued as of August 14, 1989, as a result of the decision of the Supreme Court of Canada, which is more fully set out in the text of the report.

1.10 (a) **Alberta Government Telephones**
RE89070 / E3.4 PT 2
(b) Complaint by Dancal Holdings Ltd. respecting AGT's proposed terms and conditions for the provision of service to Andrew Lake Lodge.
(c) The proceedings were discontinued as of August 14, 1989, as a result of the decision of the Supreme Court of Canada, which is more fully set out in the text of the report.

Section 2: Electric Utilities

Data reported in groups arranged alphabetically according to the name of the regulated utility to which the application refers. Individual applications within each group are then arranged in order of registration number.

ITEM NUMBER — APPLICATION PARTICULARS
(a) REGULATED ENTITY / REGISTRATION NUMBER / FILE NUMBER
(b) SUBJECT MATTER
(c) DISPOSITION / REFERENCE

2.01 (a) **AEC Power Ltd.**
RC89001 / C3.9.89-2
(b) For an Order approving a change in the existing rate charged by AEC Power Ltd. to the Buyers under the Syncrude Project Utilities Plant Energy Sales Agreement dated February 4, 1975, as amended by the Syncrude Project Utilities Plant Subsequent Capital Additions Agreement dated December 1, 1988.
(c) Approved / C89001 dated January 25, 1989.

2.02 (a) **Alberta Power Limited**
RE88076 / E3.5.89-59
(b) For approval of a change in the method for calculating income taxes for equity AFUDC.
(c) Application was replaced by Alberta Power Limited's January 20, 1989 application (RE89004) for rate reduction.

2.03 (a) **Alberta Power Limited**
RE88079 / E3.5.89-60
(b) For approval of a change in rates relating to the New Town of Rainbow Lake because of a change in the method of municipal taxation from a property tax to a franchise tax.
(c) Approved / E89031 dated April 12, 1989.

2.04 (a) **Alberta Power Limited**
RE89004 / E3.5.89-61
(b) For approval of:
(1) A reduction in rates to reflect lower Federal income tax rates after 1987; and
(2) A temporary Rider "M" to recover from customers the 1987 EEMA Price Adjustment amounts.
(c) (1) The Board in Order E89011 dated February 24, 1989, as amended by Order E89032 dated April 11, 1989, set final rates effective March 1, 1989 after concluding that:

Appendix 1

In the absence of evidence that there would be an increase in rates in 1989, a base rate reduction in accordance with its direction in Decision E87083 should be effected, using the percentage amount calculated by APL.

All of the excess revenues collected for income taxes from January 1, 1988 to February 28, 1989, should also be refunded on an across-the-board basis, using refund amounts from APL's calculations.

The methodology for determination and recovery of the 1987 EEMA adjustment amount was consistent with that of previous years and the Rider "M" recovery proposed by APL, should be approved.

(2) Decision E89061 dated July 11, 1989, fixed the amount of intervenors' costs and APL's external costs relating to these proceedings. The Board concluded that the respective claims for costs, in relation to the effectiveness of the submissions and interventions and the relevancy of the issues raised, were reasonable and necessarily incurred.

2.05 (a) **Alberta Power Limited**
RE89027 / RE89028 / E3.5.89-63 / E3.5.89-64

(b) For approval of a change in rates relating to the Village of Alliance and the Village of Nampa because of changes in the revenue tax rates.

(c) Approved / E89043 dated May 10, 1989.

2.06 (a) **Alberta Power Limited**
RE89042 / RE89047 / RE89060 / RE89057 / E3.5.89-65 / E3.5.89-67 / E3.5.89-66 / E3.5.89-68

(b) For approval of a change in rates relating to the Village of Rumsey, Village of Galahad, Village of Derwent and Town of Manning because of changes in the revenue tax rates.

(c) Approved / E89074 dated August 16, 1989.

2.07 (a) **Alberta Power Limited**
RE89044 / E3.5.89-62

(b) For approval of new rates, charges or schedules for electric light, power or energy furnished to its customers in Alberta for the 1989 and 1990 test years.

(c) (1) General

APL filed an application dated June 1, 1989 for approval to change existing rates, charges or schedules for electric light, power or energy furnished by APL to its customers for the test years 1989 and 1990.

In the Phase I Decision E89095 dated December 15, 1989, the Board determined APL's Rate Base and Revenue Requirement for each of the test years 1989 and 1990. A summary of the Board's findings respecting certain significant issues addressed in this Decision follows.

The Phase II proceedings were in process at year end.

(2) Sheerness 2

APL proposed to include the costs associated with its 50% share of Sheerness Unit 2 in rate base on a 5-year phase-in plan commencing on October 1, 1990. Sheerness 2 is the second unit of two generating units constructed jointly by APL and TransAlta Utilities Corporation at the Sheerness station and has a total capacity of 383 MW. Edmonton Power also proposed to include the costs associated with its Genesee Unit 2 in upstream pooled costs commencing January 1, 1990. Genesee 2 is the first unit of the Genesee station and has a total capacity of 406 MW. The Energy Resources Conservation Board (ERCB) approved commissioning date for Genesee 2 is October 1, 1989 whereas the approved commissioning date for Sheerness 2 is October 1, 1990. The Board found on a balance of probabilities that no unit was required in 1989, and only one unit may be required on October 1, 1990. The Board considered that no compelling reasons had been advanced to disturb the order of development of generation in the Province determined by the ERCB. Accordingly, the Board considered that if one unit is required in 1990 that unit should be Genesee Unit 2.

In order to achieve a better match between cost recovery and need for additional electrical capacity, the Board determined that cost recovery associated with Sheerness Unit 2 should be deferred beyond 1990.

APL was directed to hold the completed costs of Sheerness 2 as Plant Held for Future Use (PHFFU) and will be allowed to earn a reduced non-cash return on this plant consistent with the principle of risk sharing when a generating unit is completed prior to need. The Board was satisfied that the regulatory treatment of Sheerness 2 would not jeopardize the financial integrity of APL.

(3) SPC-DC Tie

The Board in its Decision E89004, dated February 15, 1989 determined that the SPC-DC Tie should be excluded from rate base in 1989. APL in its June 1, 1989 application proposed that the SPC-DC Tie be included in 1989 and 1990 rate base. The Board found that there were no significant changes in circumstances to warrant a different regulatory treatment from that accorded the SPC-DC Tie in Decision E89004. Accordingly, the Board excluded the SPC-DC Tie from 1989 and 1990 rate base.

(4) Fair Return

APL requested a rate of return on common equity deemed to finance rate base of 14.5% for 1989 and 14.25% for 1990 which resulted in a composite rate of return on rate base of 10.8% for 1989 and 10.8% for 1990. Intervenors submitted that the rate of return on common equity should be 12.5% for 1989 and 12.25% for 1990. The Board determined the rate of return on common equity to be 13.5% for 1989 and 1990 resulting in a composite rate of return on rate base of 10.4% for 1989 and 10.4% for 1990.

(5) Reserve For Injuries And Damages

APL requested that the Board allow credits to the Reserve for Injuries and Damages in the amount of $1,835,000 in each of 1989, 1990

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and 1991 to re-establish the Reserve at a level of $3,800,000. APL had exhausted the Reserve through charges of $4,167,000 related to an equipment failure at the Battle River 5 generating station in 1988.

The Board determined that the components of the $3,800,000 Reserve represent the maximum customer supported indemnification for single losses occurring in each of the specified categories of insured and uninsured losses. Accordingly, the Board disallowed certain charges that APL had made to the Reserve and determined that an amount of $811,000 in each of 1989, 1990 and 1991 was required to re-establish the Reserve.

(6) Forecast Sales and Sales Revenues

The Board noted that APL had, over the past five years, underforecast energy sales by an average of 4%. To reflect the consistent historical underforecasting of energy sales, the Board made a conservative upward adjustment to APL's 1990 energy sales of 1%.

(7) Revenue Deficiency/Surplus

APL proposed that unbilled revenues in the amount of $16,575,000 be used to offset a revenue deficiency of $16,327,000 in 1989. APL also forecast a revenue deficiency of $22,251,000 in 1990.

The Board determined a revenue deficiency of $4,382,000 in 1989 and agreed with APL that this deficiency should be offset by the unbilled revenues. The Board directed APL to file a proposed method of refunding the remaining unbilled revenues amounting to $12.2 million.

2.08 (a) **Alberta Power Limited**
RE89068 / E3.5.89-69
(b) For approval of a change to Rate Rider "A" for the listing of the Town of Fairview.
(c) Approved / E89088 dated September 8, 1989.

2.09 (a) **Alberta Power Limited**
RE89105 / E3.5.87(1)(e)-35
(b) For an Order approving the purposes of, and authorizing the issue of 10.20% Debentures 1989 Series to Canadian Utilities Limited in the principal amount of $105,000,000.
(c) Order E89120 dated December 22, 1989, approved the issue and the purposes of the issue.

2.10 (a) **Alberta Power Limited**
RE89109 / E3.5.89-70
(b) For approval of a change to Rate Rider "A" for the listing for the Village of Minburn.
(c) In process at year end.

2.11 (a) **Alberta Power Limited**
RE89110 / E3.5.89-71
(b) For approval of a change to Rate Rider "A" for the listing for the Town of Wembley.
(c) In process at year end.

2.12 (a) **Border Power Ltd.**
RE89107 / E3.8.89-6
(b) For approval to change existing rates, tolls and charges for electric light, power or energy furnished to its customers in Alberta for the 1989 and 1990 test years.
(c) In process at year end.

2.13 (a) **TransAlta Utilities Corporation**
RE89032 / E3.6.89-21
(b) For approval to change existing rates, tolls and charges for electric light, power or energy furnished to its customers in Alberta for the test years 1988, 1989 and 1990.
(c) (1) General

In Order C88027 dated November 14, 1988, the Board directed TransAlta to file information which would enable the Board to fix just and reasonable rates for the 1988, 1989 and 1990 test years. On May 1, 1989, TransAlta submitted a filing in response to Order C88027.

In the Phase I Decision E89091 dated December 15, 1989, the Board determined TransAlta's Rate Base, Fair Return and Revenue Requirement for each of the test years 1988, 1989 and 1990. A summary of the Board's findings respecting certain significant issues addressed in this Decision follows.

The Phase II proceedings were in process at year end.

(2) Sheerness Unit 2

TransAlta proposed to include the costs associated with its 50% share of Sheerness Unit 2 in Rate Base on a 5-year phase-in basis commencing October 1, 1990. Sheerness Unit 2 is the second unit of two generating units constructed jointly by TransAlta and Alberta Power Limited at the Sheerness station and has a total capacity of 383 MW. Edmonton Power (EP) also proposed to include the costs associated with its Genesee Unit 2 in upstream pooled costs commencing January 1, 1990. Genesee Unit 2 is the first unit of the Genesee station and has a total capacity of 406 MW. The Energy Resources Conservation Board (ERCB) approved commissioning date for Genesee Unit 2 is October 1, 1989 whereas the approved commissioning date for Sheerness Unit 2 is October 1, 1990. The Board found on a balance of probabilities that no unit was required in 1989, and only one unit may be required on October 1, 1990. The Board considered that no compelling reasons had been advanced to disturb the order of development of generation in the Province determined by the ERCB. Accordingly, the Board considered that if one unit is required in 1990, that unit should be Genesee Unit 2.

In order to achieve a better match between cost recovery and need for additional electrical capacity, the Board determined that cost recovery associated with Sheerness Unit 2 should be deferred beyond 1990.

TransAlta was directed to hold the completed costs of Sheerness Unit 2 as Plant Held For Future Use (PHFFU) and will be allowed to earn a reduced non-cash return on this plant consistent with the principle of risk sharing when a generating unit is completed prior to need. The Board was satisfied that the regulatory treatment

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of Sheerness Unit 2 would not jeopardize the financial integrity of TransAlta.

(3) Keephills-Ellerslie System Costs

The Board in Decision E89004 dated February 15, 1989, determined that the portion of the Keephills-Ellerslie System costs applicable to EP should be excluded from Rate Base in 1989 and held in PHFFU until such time as Genesee Unit 2 was added to Rate Base. TransAlta in its May 1, 1989 filing proposed that these costs be included in the 1989 and 1990 Rate Base. The Board found that there were no significant changes in circumstances to warrant a different regulatory treatment from that accorded the Keephills-Ellerslie System in Decision E89004 for the test year 1989.

The Board, having determined that Genesee Unit 2 is required in 1990, included the portion of the Keephills-Ellerslie System costs applicable to EP in TransAlta's Rate Base in 1990.

(4) Coal Rights and Leases

In response to the Board's direction in Decision E85129 dated November 25, 1985, TransAlta filed evidence in support of its inclusion in Rate Base of all coal rights and leases held for future potential power plants. The Board considered that customers (past, present and future) have and will continue to benefit from the past regulatory treatment related to such properties (i.e. inclusion in Rate Base). The Board also noted that the quantum of revenue contribution from export sales has been enhanced by the past regulatory treatment and is sufficient to cover the cash carrying costs of coal rights and leases held for future potential power plants.

(5) Keephills Units 3 and 4

TransAlta proposed that it be allowed to write-off some $62 million of expenditures it had incurred on Keephills Units 3 and 4. The Board noted that the high level of growth in 1980 and 1981 led TransAlta to the belief that Keephills Units 3 and 4 were required to meet forecast generating requirements in the mid 1980s. However, this view was not shared by the ERCB inasmuch as TransAlta's application to construct these units was denied in May, 1980 and again in February, 1982. Nor was TransAlta's view shared by the Electric Utility Planning Council (EUPC). The Board was not persuaded that TransAlta fully acted in the best interests of electric consumers during the time frame in which the Keephills Units 3 and 4 expenditures were incurred. The Board also noted that the Keephills Units 3 and 4 expenditures had been rendered of no value due to equipment obsolescence. The Board, in the circumstances, considered there should be approximately equal sharing of the "sunk" costs respecting Keephills Units 3 and 4 between customers and shareholders.

(6) Depreciation

TransAlta proposed a reduction in the life span of steam generating units from 40 years to 35 years to recognize technological obsolescence and environmental control. TransAlta also proposed to change the interim retirement curve for steam units from a square curve to a 58R3 curve.

The Board agreed with TransAlta that depreciation rates should be increased and accepted, for the purposes of this Decision, TransAlta's reduction to life span. However, the Board was not persuaded that the combined effect of the proposed life span reduction and the change in interim retirement curve was appropriate. Accordingly, the Board did not accept the change to the interim retirement curve for the purposes of this Decision.

(7) Fair Return

TransAlta requested a rate of return on common equity deemed to finance Rate Base of 14.5% for 1988, 1989 and 1990 which resulted in a composite rate of return on Rate Base of 11.4% for 1988, 11.2% for 1989 and 11.1% for 1990. Intervenors submitted that the rate of return on common equity should be 13 ¼% for 1988, 12 5/8% for 1989 and 12% for 1990. The Board determined the rate of return on common equity to be 13.5% for 1988, 1989 and 1990 resulting in a composite rate of return on Rate Base of 11.0% for 1988, 10.8% for 1989 and 10.7% in 1990.

(8) Necessary Working Capital

The Board accepted the use of the Lead/Lag Method in calculating the working capital requirements for operating and maintenance (O&M) items. The major changes made by the Board were to reduce the number of revenue lag days by recognizing unbilled revenues, to give effect to the leads/lags related to financial items and to reduce the unamortized software development costs.

(9) Capitalization of Economy Energy Earnings

TransAlta proposed to capitalize net earnings from Inter-Utility interchange sales and B.C. export sales in the amounts of $13.8 million in 1989 and $8.8 million in 1990. Under the existing regulatory treatment, the entire amount of interchange and export revenues would be credited to current customers.

The Board considered that current customers are bearing all of the fixed and incremental costs required to produce the Inter-Utility sales energy and should therefore receive all of the benefits on a current basis.

The Board considered that the net earnings from B.C. export sales should be used to cover the cash carrying costs of coal reserves held for future potential generating units as well as to provide a reasonable contribution towards current fixed costs being borne by current customers. Accordingly, TransAlta's proposal to capitalize economy energy earnings was denied.

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(10) Income Taxes

TransAlta proposed, effective January 1, 1988, to pay income tax on the preferred and common equity components of AFUDC earnings associated with assets under construction prior to the inclusion of such assets in Rate Base. The Board considered that recognition of taxes prior to the assets being placed in Rate Base results in a prepayment of taxes prior to the requirement of the assets. Accordingly, the Board denied TransAlta's proposal for each of the three test years.

(11) Revenue Surplus/Deficiency

TransAlta in its May 1, 1989 filing identified a revenue deficiency of $11.2 million in 1988, $17.5 million in 1989 and $80.5 million in 1990. The Board determined a revenue surplus of $37.1 million in 1988 and $62.9 million in 1989. While a revenue surplus of $5.2 million has been determined for the 1990 test year, the Board expects that this surplus will be offset by an increase in the final forecast 1990 EEMA (the Alberta Electric Energy Marketing Agency) transfer payment. The Board directed TransAlta to file a proposed method of refunding the $100.0 million ($37.1 + $62.9) revenue surplus commencing in 1990.

2.14 (a) **TransAlta Utilities Corporation**
RC89034 / C3.6.87(1)(c)&(g)-15

(b) For an Order to increase the aggregate principal amount of Medium Term Secured Debentures, Series A from $200,000,000 to $250,000,000 and approval for the purposes of, and authorizing the issue of the additional Debentures.

(c) Approved / C89023 dated May 30, 1989.

2.15 (a) **TransAlta Utilities Corporation**
RC89039 / C3.6.87(1)(e)&(g)-16

(b) For an Order approving the purposes of, and authorizing the issue of $100,000,000 principal amount of 10 ⅛% Secured Debentures, Series P.

(c) Approved / C89029 dated June 21, 1989.

Section 3: Electric Energy Marketing Act Proceedings

Data arranged in order of registration number.

APPLICATION PARTICULARS
(a) REGULATED ENTITY / REGISTRATION NUMBER / FILE NUMBER
ITEM (b) SUBJECT MATTER
NUMBER (c) DISPOSITION / REFERENCE

3.01 (a) **Alberta Power Limited / Edmonton Power / TransAlta Utilities Corporation**
RE88025 / E3.5.5/87 (Costs) / E3.6.5/87 (Costs) / E3.16.5/87 (Costs)

(b) Determination of intervenors' costs and applicants' external costs incidental to the proceedings to adjust the price at which Alberta Power Limited, Edmonton Power and TransAlta Utilities Corporation shall sell electric energy to the Electric Energy Marketing Agency in 1987 (1987 EEMA Adjustment Proceeding).

(c) In Order E89039 dated June 15, 1989, the Board fixed intervenors' costs and applicants' external costs in the amount of $769,479.70.

The Board had requested that all parties to the 1987 EEMA Adjustment Proceeding coordinate their activities to eliminate overlap and reduce costs. Following the proceedings, the value of the contribution of each participant was evaluated. If there was a joint effort involving two or more participants, the joint contribution was evaluated and an individual assessment was made to each participant. The Board held a cost hearing on April 5, 1989. Costs claimed by the applicants (external) and intervenors amounted to $480,961.46 and $503,920.33 respectively, totalling $984,881.79.

With respect to TransAlta, the Board determined that the costs of TransAlta's policy of involving counsel in every aspect of the regulatory proceedings should not be paid in their entirety by electric consumers in Alberta, and that the hours spent by TransAlta's counsel were excessive given the use by TransAlta of Mr. Patterson as general advisor and the expertise of TransAlta's general counsel. The Board, accordingly, approved costs of $137,787.27 for TransAlta. TransAlta had claimed costs of $243,325.27.

The City of Calgary claimed total costs of $116,717.43. The Board determined that the use by Calgary of two general consultants led to some duplication of effort, and that, given the depth with which Calgary covered the issues, Calgary's contribution to the proceedings justified an award of costs totalling $79,249.57.

The City of Lethbridge and the City of Red Deer shared consulting services and provided jointly prepared argument and reply. Claimed costs for Lethbridge and Red Deer totalled $141,777.66. Because the evidence provided on the issues of classification of transmission plant and the treatment of interruptible loads did not differ materially from evidence provided in previous EEMA proceedings, the Board considered that this constituted a duplication of effort and accordingly awarded the Cities of Lethbridge and Red Deer a total of $115,577.28.

The Board awarded costs to the other participants in the proceeding based on each participant's contribution.

3.02 (a) **Alberta Power Limited / Edmonton Power / TransAlta Utilities Corporation**
RE88055 / RE88056 / RE88057 / E3.5.3/89 / E3.16.3/89 / E3.6.3/89

(b) Filings dated September 2, 1988, as amended, respecting the prices at which APL, EP and TransAlta shall sell electric energy to the Electric Energy Marketing Agency (EEMA) for 1989 on a forecast basis.

(c) The Board held hearings in respect of this matter in November and December 1988 and issued its findings in Decision E89004 dated February 15, 1989. A summary of the Board's findings is set out below.

(1) Jurisdictional Issues

The Board considered that the rate base methodology and the "used or required to be used" test as set out in the Public Utilities Board

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Act (PUB Act), are applicable when setting the price or pricing formula pursuant to Section 13.1 of the Electric Energy Marketing Act (EEM Act).

The Board considered that its use of the PUB Act and the "used or required to be used" test does not in any way encroach upon the ERCB's authority respecting construction of plant or commissioning or operating dates.

(2) Issues Related to Alberta Power Limited

(A) SPC-DC Tie

The Board excluded from upstream rate base the cost of a significant transmission system, namely the SPC-DC tie interconnection between Saskatchewan and Alberta, following its determination that the system was not required to serve Alberta electric consumers in 1989. The Board directed that the investment in the SPC-DC tie be held as Plant Held For Future Use (PHFFU). Excluding the SPC-DC tie from upstream rate base would have no appreciable effect on Alberta Integrated System (AIS) customers or APL in 1989.

(B) Little Smoky/Wesley Creek Transmission Line

The Board accepted for the purposes of Decision E89004, APL's proposal to add to the 1989 upstream rate base the Little Smoky/Wesley Creek Transmission line since it considered that the line would be used or required to be used in 1989.

(C) Operating and Maintenance Expenses

The Board, for the purposes of Decision E89004, accepted as reasonable the O&M expenses proposed by APL subject to any adjustments resulting from its determination related to the SPC-DC tie and Genesee 2.

(3) Issues Related to Edmonton Power

(A) Genesee 2 Power Plant

The Board determined that electric industry reliability standards were clearly met and exceeded in 1989 without the connection of Genesee 2 to the Alberta electric grid. Accordingly, the Board determined that the Genesee 2 power plant was not required to be used in 1989 and therefore excluded from EP's 1989 costs to the Agency, all costs related to Genesee 2. The Board noted that the effect of excluding Genesee 2 from rate base and Genesee 2 related costs from AIS upstream costs was a cost savings of $60.4 million in 1989 to AIS customers. The Board also noted that its decision did not preclude EP from operating Genesee 2 in 1989 if it so desired. The Board directed that the investment in Genesee 2 be held as PHFFU and provided a return thereon. By holding the investment in PHFFU in this manner, the Board considered that the financial integrity of EP would not be impaired.

The Board also determined the appropriate treatment for Allowance for Funds Used During Construction (AFUDC), common costs, mine land costs and mine equipment costs, to be included in PHFFU with respect to the Genesee 2 investment.

(B) Depreciation Policies, Procedures and Reasonableness

The Board approved EP's depreciation policies and procedures and accepted as reasonable EP's depreciation calculations for 1989.

(C) Operating and Maintenance Expenses

The Board considered that the 1988 (updated) fuel gas quantities per GWh would provide a more reasonable basis for estimating the 1989 forecast gas costs for the Clover Bar generating station than the method used by EP. Accordingly, EP was directed to recognize this finding in its EEM Act Section 5(1) refiling.

The Board accepted as reasonable EP's O&M expenses subject to the above and subject to any adjustments resulting from its determination respecting Genesee 2.

(4) Issues Related to TransAlta Utilities Corporation

(A) Keephills/Ellerslie Transmission Line

The Board excluded from upstream rate base a major portion of the cost of a significant transmission line, namely the Keephills/Ellerslie line Phase 2, following its determination that the line was not required to be used in 1989 consistent with the Board's treatment of the Genesee 2 plant. The Board directed that the investment in the Keephills/Ellerslie line be held as PHFFU. Excluding the Keephills/Ellerslie line from upstream rate base would have no appreciable effect on AIS customers or TransAlta in 1989.

(B) Ghost Upgrade Project

The Board, for the purposes of Decision E89004, accepted TransAlta's proposal to include the costs of the above project in rate base.

(C) Computers and Equipment Property Additional

The Board, for the purposes of Decision E89004, accepted TransAlta's proposal to include the costs of the above items in rate base.

(D) Operating and Maintenance Expenses

The Board, for the purposes of Decision E89004, accepted as reasonable the O&M expenses proposed by TransAlta subject to any adjustments resulting from the Board's determinations relative to the Keephills/Ellerslie line and Genesee 2.

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(5) General Issues

(A) Sales to B.C. Hydro

The Board considered that variations in forecast sales to B.C. Hydro would have a minimal effect on EEMA transfer payments. Accordingly, the Board accepted the forecast of B.C. Hydro sales for the purposes of Decision E89004.

(B) Rate of Return (Including Common Equity) to be Used in AFUDC Calculations

The Board considered that the AFUDC rate used for a year should be reflective of the utility's cost of capital for that year irrespective of whether a rate of return had been determined by the Board for that year. However, for practical reasons, a rate of return on common equity equal to or less than the last Board established rate may be used for AFUDC calculations, if the circumstances warrant such use.

(C) AIS Adjustment to Installed Capacity

The Board was not persuaded that a proposed 225 MW reduction in the Alberta Integrated System (AIS) installed capacity resulting from a downward adjustment to the peak continuous rating (PCR) of generating units was justified at this time. Accordingly, the Board did not accept the proposed 225 MW PCR reduction in calculating the AIS capacity for 1989.

(D) AIS Planned Retirements

The Board considered that the Firm Load Carrying Capability (FLCC) of the AIS was not materially affected whether or not Rossdale Units 6 and 7 were included or excluded from FLCC studies due to the current high forced outage rates of these units. Accordingly, the Board considered it unnecessary to make any adjustments to the 1989 Surplus Load Carrying Capability calculations due to these planned retirements.

(E) Consumer Group Demands

The Board agreed with intervenors that growth in EP's residential consumer group demand appeared to be high compared with growth in APL and TransAlta consumer group demand. Accordingly, EP was directed to recognize this finding in its EEM Act Section 5(1) refiling.

(6) Refilings

(A) Board Directions

The Board directed the Utilities to reflect the corrections/changes to the October 14, 1988 filings, agreed to by the Utilities during the Proceedings. The Board directed the Utilities to reflect its findings as above in a refiling of the 1989 forecast prices to EEMA, by February 20, 1989.

(B) Utility Refilings

APL, EP and TransAlta resubmitted their filings on February 20, 1989 in compliance with the Board's directions. On February 24, 1989, the Board issued Order E89007 setting the price for which APL would sell electric energy to EEMA in 1989; Order E89008 setting the price for which EP would sell electric energy to EEMA in 1989; and Order E89009 setting the price for which TransAlta would sell electric energy to EEMA in 1989.

(7) Costs Awards

In Order E89036 dated June 15, 1989 the Board fixed and approved intervenors' costs and the utilities' external costs in the amount of $1,065,024.35.

In the Pre-Hearing Conference, held September 23, 1988, the Board set out the following guidelines by which cost claims would be considered:

- effectiveness of submissions and interventions
- relevancy to identified significant issues
- whether the costs were reasonably and necessarily incurred.

In assessing costs, the Board considered the contribution of each participant and where contributions were made jointly or where specific issues were dealt with, the Board evaluated the contributions and allocated costs based on the value of those contributions.

TransAlta claimed total external costs of $178,555.21. The Board, in awarding TransAlta costs of $114,584.21, determined that not all of the costs associated with TransAlta's policy of involving counsel in every stage of the regulatory process should be borne by Alberta electric consumers. The Board further determined that the use of Mr. M. Patterson and experienced counsel should contribute to a reduction in chargeable hours.

EP, as a major participant in the proceedings, claimed external costs of $440,658.81. The Board found the total billable hours of 2107.5 for EP's counsel and consultants excessive and determined that the use of two general consultants by EP led to a duplication of effort. The Board, however, considered the costs relating to EP's depreciation evidence to be reasonably and necessarily incurred. EP's disbursements for travel were adjusted to reflect economy class fares. The Board awarded EP total costs of $287,742.51.

The City of Calgary claimed costs totalling $184,567.37. The Board reviewed Calgary's use of 2 general consultants; the number of hours claimed; the depth and complexity of issues dealt with, and determined that Calgary's claim was excessive. The Board also determined that the costs of preparing

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income tax evidence on the equity portion of AFUDC amounting to $13,525.00 should be considered when this issue is dealt with by the Board. The Board awarded Calgary total costs of $118,456.70.

The Board awarded costs to the other participants in the proceeding based on each participant's contribution.

3.03 (a) **Alberta Power Limited / Edmonton Power / TransAlta Utilities Corporation**
RE89037 / E3.5.5/88 / E3.6.5/88 / E3.16.5/88

(b) Joint application dated May 11, 1989 for an Order adjusting the price or pricing formula to sell electric power to the Alberta Electric Energy Marketing Agency (EEMA) for 1988.

(c) (1) By Decision E89096 dated December 15, 1989, the Board set out its findings respecting the issues raised during the 1988 EEMA Adjustment proceedings as detailed below, and directed the Utilities to refile their Section 17(2) Filings, reflecting the Board's Findings, by December 22, 1989.

The Board accepted EP's proposed method of allocating central administration charges between current operations, construction work-in-progress and non-regulated operations, subject to certain changes to the method of allocation of financial management charges.

The Board determined that the rate of return on common equity for all three Utilities would be 13.5% for 1988.

The Board considered that the existing method of allocating low voltage substation costs was appropriate.

The Board determined that Class 3 interruptible loads should be deducted in the months of November, December, January and February for the allocation of generation demand costs, and that Class 3 loads should not be deducted in any month for the allocation of transmission demand costs.

(2) The Board approved the utilities' Section 17(2) Filings in Order E89115 dated December 29, 1989.

(3) The related costs proceedings were in process at year end.

3.04 (a) **Alberta Power Limited / Edmonton Power / TransAlta Utilities Corporation**
RE89041 / RE89043 / RE89045 / E3.5.3/90 / E3.16.3/90 / E3.6.3/90

(b) Filings dated June 1, 1989 respecting the prices for which APL, EP and TransAlta shall sell electric energy to the Electric Energy Marketing Agency (EEMA) for 1990 on a forecast basis.

(c) (1) General

By Decision E89097 dated December 15, 1989, the Board determined the basis for the price at which the three Utilities will sell electric energy to EEMA during 1990. A summary of the Board's findings respecting certain significant issues addressed in this Decision follows.

(2) Genesee Unit 2

EP proposed to include its Genesee Unit 2 in upstream pooled costs on January 1, 1990. Genesee Unit 2 is the first unit of the Genesee station and has a total capacity of 406 MW. APL and TransAlta also proposed to include the costs associated with their jointly-owned Sheerness Unit 2 on a 5-year phase-in basis commencing October 1, 1990. Sheerness Unit 2 is the second unit of two generating units at the Sheerness station and has a total capacity of 383 MW. The Board found on a balance of probabilities that no unit was required in 1989, and only one unit may be required on October 1, 1990.

The Board considered that in view of the requirement for the Genesee 2 unit in 1990 that cost recovery associated with Genesee Unit 2 should commence in 1990.

(3) Prudence and Allocation of Land Costs

EP incurred some $23 million of expenditures including bare land costs, improvements, compensation, appraisal, legal and real estate fees with respect to land purchased for the Genesee project. The Board noted that of the total $23 million some $5.4 million was paid for improvements. The Board considered that EP could have realized more proceeds through disposals had EP exercised proper stewardship of the improvements purchased. The Board adjusted EP's land cost expenditures downward by $361,160.

EP proposed on an "initial" use allocation method that $17.6 million of the $23 million should be included in 1990 upstream costs with $5.4 million held in Plant Held for Future Use (PHFFU).

The Board determined on a "primary use" allocation method that only $13.5 million should be included in 1990 rate base, $0.5 million in Construction Work in Progress (CWIP) and $8.7 million in PHFFU.

(4) Fair Return

The Board determined the rate of return on common equity for all three Utilities to be 13.5% for 1990.

(5) Utility Refilings

On December 29, 1989, the Board issued Order E89116 setting the price for which APL would sell electric energy to EEMA in 1990; Order E89117 setting the price for which EP would sell electric energy to EEMA in 1990; and Order E89118 setting the price for which TransAlta would sell electric energy to EEMA in 1990.

(6) Costs Awards

The related costs proceedings were in process at year end.

3.05 (a) **TransAlta Utilities Corporation**
RE89061 / E3.6.3/89 (Costs) R.V.

(b) For a review and variance of Board Decision E89036 dated June 15, 1989.

(c) In process at year end.

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3.06 (a) **TransAlta Utilities Corporation**
RE89062 / E3.6.5/87 (Costs) R.V.
(b) For a review and variance of Board Decision E89039 dated June 15, 1989.
(c) In process at year end.

3.07 (a) **Alberta Power Limited / Edmonton Power / TransAlta Utilities Corporation**
RE89072 / E3.6.5/87 (Costs) R.V.(2)
(b) Application by the City of Lethbridge for a review and variance of Board Decision E89039 dated June 15, 1989.
(c) In process at year end.

3.08 (a) **Alberta Power Limited / Edmonton Power / TransAlta Utilities Corporation**
RE89074 / E3.6.5/87 (Costs) R.V.(3)
(b) Application by the Alberta Association of Municipal Districts and Counties and the Alberta Federation of Rural Electrification Associations for a review and variance of Board Decision E89039 dated June 15, 1989.
(c) In process at year end.

3.09 (a) **Alberta Power Limited / Edmonton Power / TransAlta Utilities Corporation**
RE89075 / E3.6.3/89 (Costs) R.V.(2)
(b) Application by the Alberta Association of Municipal Districts and Counties and the Alberta Federation of Rural Electrification Associations for a review and variance of Board Decision E89036 dated June 15, 1989.
(c) In process at year end.

3.10 (a) **Edmonton Power**
RE89077 / E3.6.5/87 (Costs) R.V.(4)
(b) For a review and variance of Board Decision E89039 dated June 15, 1989.
(c) In process at year end.

3.11 (a) **Edmonton Power**
RE89078 / E3.6.5/87 (Costs) R.V.(3)
(b) For a review and variance of Board Decision E89036 dated June 15, 1989.
(c) In process at year end.

Section 4: Water Utilities

Data reported in groups arranged alphabetically according to the name of the regulated utility to which the application refers. Individual applications within each group are then arranged in order of registration number.

ITEM NUMBER — APPLICATION PARTICULARS
(a) REGULATED ENTITY / REGISTRATION NUMBER / FILE NUMBER
(b) SUBJECT MATTER
(c) DISPOSITION / REFERENCE

4.01 (a) **Acheson Park Water Corporation**
RE88066 / RE89026 / E3.318.1 / E3.318.89-1
(b) For approval of a change in rates and terms and conditions of service.
(c) Order E89113 dated December 12, 1989 amended and clarified Order E88087 with respect to the terms and conditions of service currently in effect, pending the Board's final determination of the outstanding applications.

Section 5: Natural Gas Utilities

Data reported in groups arranged alphabetically according to the name of the regulated utility to which the application refers. Individual applications within each group are then arranged in order of registration number.

ITEM NUMBER — APPLICATION PARTICULARS
(a) REGULATED ENTITY / REGISTRATION NUMBER / FILE NUMBER
(b) SUBJECT MATTER
(c) DISPOSITION / REFERENCE

5.01 (a) **Bonnyville Gas Company Limited**
RE88071 / E4.5.35-22
(b) for approval of a change in the existing rates, tolls and charges for natural gas supplied and services rendered to its customers within Alberta.
(c) (1) General

(A) Order E89003 denied the Company's application for an interim increase in rates on a refundable basis.

(B) Phase I Decision E89014 dated August 2, 1989 determined the rate base, fair return and utility revenue requirement for the 1988 and 1989 test years.

(C) Phase II Decision E89114 dated December 20, 1989 dealt with the Company's August 10, 1989 filing for a change in existing rates, tolls and charges effective on all consumption on and after January 1, 1990 to recover the non-gas component of the 1989 revenue requirement determined in the Board's Phase I Decision.

(2) Rate Base

(A) Additions

The Board reduced the Company's 1988 plant additions forecast by a total of $6,500 for work not expected to be completed in 1988 with respect to installation of above ground valves and the replacement of PE3306 pipe. The total amount of $6,500 not expended in 1988 was added to the total plant additions program for 1989 in view of the Company's assurance the programs are proceeding.

(B) Retirements

The Company indicated that its methodology for estimating retirements when the vintage or original cost of the retired asset was unknown complied with the methodology previously approved by the Board.

(C) Accumulated Depreciation

The Board agreed with the Company's position that a revised Depreciation Study that differentiates assets by plant account, type and size should be filed at the next General Rate Application.

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(D) Allowance for Working Capital

Company witnesses indicated that approximately 30% of the O & M inventory was for capital projects and the remaining 70% was for system operating and maintenance. Therefore, the Board reduced the forecast operating and maintenance inventory for inclusion in Necessary Working Capital by 30 percent.

The Board accepted the Company's forecast of deferred regulatory expenses of $5,000 for 1988 and $12,500 for 1989.

(3) Fair Return on Rate Base

(A) Capital Structure

The Board considered that the Company's capital structure was appropriate except for Bank Advances. However, due to the fact that the Company had been recently purchased by ICG the Board included Bank Advances in the capital structure for purposes of this Decision.

(B) No Cost Capital

The Company forecast grants of $226,800 from Alberta Transportation and Utilities in 1989 for PVC pipe replacement. The Company acknowledged in response to Board examination that it was doubtful that these grants would be forthcoming. Hence, the Board recalculated the 1989 Contributions In Aid of Construction balance to reflect a reduction of $226,800.

(C) Cost of Capital

The Board allowed a 14.0% rate of return on common equity deemed to be financing the Company's rate base for each of the years 1988 and 1989, noting that capital was attracting a higher return than when the Board approved a 13.25% rate of return on common equity for NUL.

(4) Utility Revenue Requirement

(A) Cost of Gas

The Board approved the Company's estimate of $39,373 as the cost of gas in 1988, but based on adjustments to the Company estimate of the 1989 normalized sales volume (see Section (c)(5)(A)), the Board determined the cost of gas for 1989 to be $42,994 rather than the $42,175 estimated by the Company.

(B) Cash Operating Expenses

Data Processing

The Company stated that its in-house computer system could no longer be maintained alone in 1989, hence it was appropriate to use the central Data Processing Department of ICG Utilities (Greater Winnipeg Gas Ltd.) in 1989 at a fee of $46,500. The Company stated that approximately $29,000 of expenses associated with Data Processing in 1988 were included in the expense Customer Accounting. The Board allowed the forecast amounts for Data Processing of zero for 1988 and $46,500 for 1989, respectively.

Moving Expense

The Company forecast moving expenses of $20,000 and $5,000 for 1989. The 1988 moving expenses were incurred to relocate a former ICG employee to serve as Manager of the Company. The Board considered that the actual level of costs incurred respecting this relocation, namely $24,577, was influenced at least in part by the Company's response to policies of Inter-City Gas Corporation. The Board approved the original forecast amount of $20,000 for 1988 moving expenses. However, the forecast of $5,000 for 1989 moving expenses was considered speculative and was disallowed.

Insurance Premium

In 1988, the Company cancelled all of its existing insurance policies and coverage was obtained under the umbrella of Inter-City Gas Corporation (Inter-City) policies. The Town indicated that the Company incurred penalty charges of $2,059.25 due to cancellation of its insurance policies. The Board considered it unnecessary for the Company to have incurred these penalty costs and therefore reduced insurance premium expense by $2,059 for 1988.

Support Services ICG

The Company's head office support service charges were forecast at $8,200 for 1988, with the final actual billing set at $7,400. As a result, the Company's forecast of total support service charges from ICG for 1988 was reduced by $800 in recognition of those services which were not required or used by the Company.

Vehicle Expenses

Based on actual vehicle expenses booked to November 30, 1988, the Company acknowledged that the vehicle expense forecast for 1988 was in the order of $5,000 - $7,000 too high. Accordingly, the Board reduced 1988 vehicle expenses by $6,000, which was mid-point at the range of the overestimate.

Meter Reading

After taking into account the actual meter reading expense booked to November 30, 1988, the Board considered it appropriate to reduce the Company's forecast of meter reading expenses by $6,000 for each of the test years 1988 and 1989.

Advisory Board

The Advisory Board was composed of all six of the former members of the Board of

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Directors of the Company who had been retained in an advisory capacity for a period of two years at the same fees they received previously as Directors. The Board considered that the Advisory Board had been of some value to the Company notwithstanding that they had only two formal meetings in the period January 1, 1988 to the date of the Phase I Decision, August 2, 1989. Therefore, the Board considered it appropriate to allow only $20,000 for Advisory Board expenses for each test year (1988 and 1989) rather than the $43,200 requested by the Company for each year.

Employee Benefits

In light of the actual employee benefits recorded to November 30, 1988, the Company acknowledged that the forecast for the 1988 test year appeared about $6,000 too high and accordingly, the Board reduced the Company's forecast of employee benefits for each of the test years 1988 and 1989 by $6,000.

Municipal Taxes

The Company's estimate of municipal taxes pertaining to the Town of Bonnyville for the 1988 and 1989 test years reflected an escalation rate of about five percent per year over the actual level experienced in 1987. The Board considered an escalation rate reflective of inflation to be more appropriate and hence used a factor of 3.5% in 1988 and of 4.5% for 1989. These adjustments resulted in decreases to the Municipal Tax forecast for 1988 and 1989 of $300 and $468 respectively.

Income Taxes

The Company had originally forecast no Income Taxes for each of the test years 1988 and 1989. The Company submitted that it was eligible to claim capital cost allowance in excess of its requirement; however, capital cost allowance was forecast only in sufficient amounts to bring taxable income to zero. Based on Board revised Cash Operating Expenses and claiming maximum Capital Cost Allowance in each of the two test years, the Board determined forecast income taxes for 1988 and 1989 of $10,541 and $4,700, respectively.

(5) Utility Revenues

(A) Normalized Sales Forecast

The Company's 1989 forecast of normalized average annual consumption per customer data reflected a decline of approximately 0.9 percent from the 1988 levels. The Company submitted the 1989 forecast decline in consumption per customer reflected the continuing emphasis on conservation by government and customers. The Board considered that the Company had not produced sufficient evidence to warrant approval of the normalized average annual consumption per customer data for 1989.

The Board therefore recalculated 1989 normalized sales volumes using normalized average annual consumption per customer data for 1988 and the average number of customers for 1989.

(B) Amortization of the Border Flowback Fund

The Company proposed to reduce its forecast revenue deficiencies of $92,624 in 1988 and $88,445 in 1989 by amortizing the Border Flowback Fund in the amount of $75,000 per year. The Board considered it appropriate to draw down the Border Flowback Fund in each of the two test years, but only in sufficient amounts to offset the Board approved forecast revenue deficiencies of $48,055 and $39,303 for 1988 and 1989, respectively.

(6) Rates - Deferred Gas Accounting

The Board approved a set of Deferred Gas Accounting procedures for the Company. These procedures required the Company to file, no later than August 18, 1989, a reconciliation of calendar year 1988 royalty expense collected and actual royalties paid, and file no later than November 1, 1989, its forecast cost of gas and estimated per unit gas cost recovery rate, adjusted to reflect the over or under recovery of royalty expenses in calendar year 1988. Based on these submissions, the Board would approve a gas cost recovery rate for billing effective on January 1, 1990 on gas consumed during the period January 1990 to December 31, 1990.

The filing procedures for years subsequent to 1989 are similar except that the reconciliation of the prior year's royalty expense must be filed no later than June 1 of each year.

(7) Security of Supply

The revised reserves data contained in the Company's D & S Reserves Study reflected a mathematical life of about 6 years. A Company witness indicated that the Company could experience deliverability problems in 2 or 3 years and not be able to meet demand. The Company noted that it had initiated a $500,000 exploration program for 1989 in response to declining reserves and deliverability and expected to have additional reserves or a gas supply contract in place prior to the 1989/1990 winter season.

The Board noted that the town had expressed concern that the Company was not ensuring that it will have adequate reserves to satisfy customer demand. The Board directed the Company to advise the Board as soon as results are available from the 1989 exploration program. Should the Company experience any delay in its 1989 exploration program, the Board directed the Company to file a progress status report by December 31, 1989.

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(8) Line Losses

The Company submitted that line losses were not included in its Application as the Company does not purchase supplies; hence, the Company does not experience a volume differential between the volume of gas purchased and sold. Further, as the Company pays royalties on its sales volume there is no apparent line losses.

The Board continued to consider it appropriate to monitor line losses and directed the Company to file line loss percentages at the time of its next General Rate Application.

(9) Rules and Regulations

The Board approved the Company's amendment of its initial Application to modify the terms of payment in its Service Regulations to reflect an extension of time for payment of customer accounts from 15 days to 21 days.

(10) Costs Awards

Order E89046 dated October 25, 1989 approved costs respecting these proceedings. All external costs as claimed by the Company in the amount of $15,342.98 were approved in full. The costs claimed by the Town of Bonnyville were reduced from $18,880.10 to $17,768.10. This reduction reflected a reduction in the hours claimed for appearance time by the Town's legal counsel and consultant and a further reduction adjusting the mileage rate for the Town's consultant from $.35/mile to $.25/mile.

(11) Schedule of Sales Rates

In Decision E89114, the Board approved an increase of $0.0498/MCF in the commodity charge effective January 1, 1990 for each of the Company's three sales rate categories. There were no changes to fixed charges levied on the Company's customers.

(12) Rider "A" (Royalty Expense)

The Board considered the calculation of the Gas Cost Recovery Rate filed by the Company to be reasonable and accepted the calculations filed in support of this Rider. Therefore, the Board set Rider "A" at a level of $0.039/MCF for all gas consumed during the period January 1, 1990 to December 31, 1990.

(13) Distribution System Tax

The Board considered the Company's calculation of the Distribution System Tax Recovery Rate to be reasonable. Accordingly, the Board set Rider "B" at 2% effective January 1, 1990. The Company was directed to file with the Board by March 31, 1990, the actual Distribution Tax levied for 1989 and a revised 1990 Rider "B" to reflect the 1989 actual tax assessment.

The Company requested implementation of "filing for acknowledgement" procedures for future Distribution System Tax filings in lieu of the current "filing for approval" procedures. The Board concurred with the Company's assertion that the derivation of the Distribution System Tax Rider was not normally a complicated matter necessitating the need for a public hearing. Accordingly, filing for acknowledgement was considered appropriate for future Distribution System Tax filings. The Board directed the Company to submit future Distribution System Tax filings to the Board and Town (as well as other known intervenors) concurrently.

(14) Late Payment Penalty

The Company's proposal to charge a 5% late payment penalty to be effective January 1, 1990 was consistent with the Board approved late payment penalty for the 1988 and 1989 test years. Accordingly, the Board approved the Company's request for a late payment penalty of 5% effective January 1, 1990.

5.02 (a) **Canadian-Montana Gas Company Limited**
RE88064 / E4.23.3(1)(b)

(b) For an Order declaring that, for the purposes of the Public Utilities Board Act and the Gas Utilities Act, the Applicant is not an owner of a public or a gas utility.

(c) In process at year end.

5.03 (a) **Canadian-Montana Gas Company Limited**
RE88065 / E4.23.24(1)(g) / E6.405.5-4

(b) (1) For approval of the sale of certain assets to Forty Mile Gas Co-op Ltd. The assets for which approval of the sale was sought were those assets used by Canadian-Montana Gas Company Limited to provide natural gas service to customers within the Hamlet of Manyberries.

(2) For approval to terminate the franchise agreement between Canadian-Montana Gas Company Limited and the Municipal District of Forty Mile No. 2 (the predecessor of the County of Forty Mile No. 8). The franchise agreement was for the area which includes the Hamlet of Manyberries.

(c) In Order E89090 dated September 21, 1989, the Board gave its approval to these applications. In Decision E89090 dated September 21, 1989, the Board provided reasons for its decision. The Board considered that as Forty Mile Gas Co-op Ltd. has received the approval from the Department of Transportation and Utilities to amend its franchise area to include the Hamlet of Manyberries, and as Forty Mile Gas Co-op Ltd. has undertaken to serve customers in the Hamlet of Manyberries at its current rate ($2.76/GJ and $12.00 monthly fixed charge) which is lower than the estimated rate determined for Canadian-Montana Gas Company Limited in the Board's Cost of Service Study ($5.06/GJ), the applications should be approved.

5.04 (a) **Canadian Western Natural Gas Company Limited**
RE88037 / E4.7.35-70

(b) Application by the Calgary District Hospitals Group, et al. for an Order directing Canadian Western Natural Gas Company Limited to provide gas transportation service.

(c) By letter dated May 15, 1989 the Calgary District Hospitals Group, et al. notified the Board that it was withdrawing its application.

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5.05 (a) **Canadian Western Natural Gas Company Limited** RC89014 / RC89017 / RC89021 / C4.7.35-75 / C4.7.35-76 / C4.7.35-77

(b) For approval of a change to Rate Rider "A" relating to the Villages of Irricana, Carmangay, and Barons because of a change in the revenue tax rate.

(c) Approved / C89014 dated April 26, 1989.

5.06 (a) **Canadian Western Natural Gas Company Limited** RE89014 / E4.7.35-74

(b) For approval of a revised Gas Cost Recovery Rate (GCRR) for the summer period from April 1, 1989 to October 31, 1989 inclusive and a reconciliation of the actual gas costs with the actual gas cost recoveries for the prior summer period (April 1, 1988 to October 31, 1988 inclusive).

(c) In Order E89020 dated April 4, 1989, the Board approved a 16.9 cent/GJ decrease to the previously approved summer GCRR of $1.392/GJ, fixed in E88038 dated March 29, 1988.

With respect to the over collections held in the Deferred Gas Account (DGA), CWNG took the position that no interest should be attached to such over collections since (i) they are insignificant compared to the overall cash flows; (ii) a General Rate Application, when all other cash flows are examined, would be the more appropriate forum to deal with the interest issue and (iii) CWNG was anticipating some gas supply rebates from the Provincial Government that would offset the over collections. CWNG also submitted that a three to four year period, rather than a six month period, be considered to determine whether the over(under) collections have been persistent. Further, the Board should accept a range of ±4% to ±5%, of the total annual gas supply costs, as a reasonable tolerance limit for the over(under) collections held in the DGA.

The Board considered, based on the evidence presented, that CWNG's forecast of its 1989 summer GCRR of $1.223/GJ was reasonable. However, inasmuch as CWNG's negotiations with its long-term producers and other suppliers had not been completed, the Board expected that CWNG would advise the Board of the settlements as soon as possible.

5.07 (a) **Canadian Western Natural Gas Company Limited** RC89024 / RC89025 / RC89026 / C4.7.35-78 / C4.7.35-79 / C4.7.35-80

(b) For approval of a change to Rate Rider "A" relating to the Village of Carbon, Village of Acme, and the Village of Beiseker because of a change in the revenue tax rate.

(c) Approved / C89022 dated May 10, 1989.

5.08 (a) **Canadian Western Natural Gas Company Limited** RC89032 / C4.7.35-81

(b) For approval of a change to Rate Rider "A" relating to the Village of Champion because of a change in the revenue tax rate.

(c) Approved / C89031 dated July 5, 1989.

5.09 (a) **Canadian Western Natural Gas Company Limited** RC89033 / C4.7.35-82

(b) For approval of a change in rates relating to the Town of Strathmore because of a change in the method of municipal taxation from a property tax to a franchise tax.

(c) Approved / C89026 dated June 6, 1989.

5.10 (a) **Canadian Western Natural Gas Company Limited** RC89041 / C4.7.35-84

(b) For approval of a change in rates relating to the Town of Vulcan because of a change in the method of municipal taxation from a property tax to a franchise tax.

(c) Approved / C89036 dated July 19, 1989.

5.11 (a) **Canadian Western Natural Gas Company Limited** RC89042 / C4.7.35-83

(b) For approval of a change to Rate Rider "A" relating to the Town of Stavely because of a change in the revenue tax rate.

(c) Approved / C89035 dated July 19, 1989.

5.12 (a) **Canadian Western Natural Gas Company Limited** RC89052 / E4.7.35-89

(b) For approval of a change in rates for the 1989, 1990 and 1991 test years.

(c) In process at year end.

5.13 (a) **Canadian Western Natural Gas Company Limited** RE89052 / E4.7.35-85

(b) An application by the City of Calgary dated June 21, 1989 pursuant to Part II of the Public Utilities Board Act, and in particular Section 81 thereof, requesting that the Board hold a hearing into the rates, tolls or charges for natural gas service provided by CWNG for 1989 and thereafter.

(c) Decision C89037 dated August 2, 1989, approved the application and ordered that CWNG file by November 1, 1989 complete particulars, information and data to enable the Board to fix, inter alia, just and reasonable rates, tolls or charges for the test years 1989/90/91. In so doing, the Board proceeded as if the application had been made pursuant to Section 28 of the Gas Utilities Act.

The City of Calgary's evidence showed that, in each year 1986 through 1988, CWNG had earned a return on shareholders' equity in excess of that approved by the Board in determining CWNG's 1986 test year revenue requirement; and that CWNG's 1989 first quarter earnings were higher than comparable earnings for 1988; and that, during those same three years, CWNG has been making large untested non-weather-related normalizations.

CWNG took a neutral position neither supporting nor opposing Calgary's application, and had not provided any 1989 forecast information to rebut Calgary's contention that CWNG's "excess earnings" might continue into 1989.

In arriving at its decision, the Board considered that:

(1) Although the earning of such "excess return" by CWNG in prior years was not necessarily an indication that such would also occur in 1989, the absence of contrary evidence from CWNG was "some indication" that CWNG anticipated returns higher than those which the Board could be expected to allow for 1989.

(2) CWNG had used untested procedures to exclude certain amounts of its actual earned income (i.e. some revenues derived from gas storage), from its reported normalized revenue.

(3) There had been a great number of operating and

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regulatory changes to CWNG's operating environment, since its last GRA for the test years 1986, each of which would affect CWNG's future earnings.

5.14 (a) **Canadian Western Natural Gas Company Limited**
RE89058 / E4.7.36-86

(b) To approve changes in the charges contained in Schedules A and B with respect to Natural Gas Sales Service Regulations.

(c) Decision C89043 dated August 31, 1989, pursuant to Section 50 of the Public Utilities Board Act, gave ex parte interim approval to the new charges in Schedules A and B to be effective commencing September 1, 1989. The major items considered in arriving at the decision were:

(1) CWNG's application arose as a direct result of an agreement regarding the fair level of winter trenching charges that CWNG reached with Calgary Home Builders' Association who, prior to that agreement, had applied to the Board for a reduction in CWNG's rates for winter trenching.

(2) The Board would be fixing, inter alia, the charges for all of the services CWNG performs under Schedules A and B based on the outcome of CWNG proceedings commencing in the fall of 1989.

(3) Due dispatch was required in order that Calgary home builders benefit from the reduced charges for installation of service lines during the forthcoming winter season.

(4) Any person entitled to notice of the application may make application to the Board pursuant to Section 50(2) of the Public Utilities Board Act to alter or rescind the order.

5.15 (a) **Canadian Western Natural Gas Company Limited**
RE89086 / E4.7.35-88

(b) For confirmation that their winter season Gas Cost Recovery Rate (GCRR) effective November 1, 1988 was still reasonable and for a change in their Rider "D" for collection of unaccounted for gas costs effective January 1, 1990.

(c) (1) In Order E89099 dated October 31, 1989, the Board approved CWNG's application, stating that the calculations and forecasts that CWNG used to derive the winter GCRR of $1.608/GJ and a Rider "D" of 1.3%, were reasonable. As a result no change to CWNG's existing rate schedules, other than to Rider "D", was required. However, the winter season rates listed on the existing rate schedules had expired on March 1, 1989.

(2) Amending Order E89106 dated November 9, 1989 specifically reinstated those winter rates.

5.16 (a) **Canadian Western Natural Gas Company Limited / Northwestern Utilities Limited**
RE87036 / RE87042 / RE87051 / RE87052 / RE87053 / RE87054 / RE87055 / RE87057 / RE87058 / RE87059 / RE88040 / RE88042 / E4.7.35-48, et al. / E4.14.35-57, et al.

(b) Applications for transportation service (T-service) by certain industrial customers of CWNG and NUL.

(c) (1) Order E89005 dated January 20, 1989, approved CWNG's and NUL's proposed interruptible transportation rates 14, 24 and 34 (based on firm T-rates 13, 20-23 and 30-33) on an interim refundable basis effective January 20, 1989. CWNG/NUL proposed that the interruptible T-rates would have a minimum service period of one calendar month and a minimum of one month advance notice. Considering that the matters addressed in Order E89005 would be addressed fully at a hearing to be convened in the near future, the Board approved the proposed interruptible transportation rates on an interim basis.

This order also approved certain amendments to Interim T-Rate 13 on an interim basis. These amendments included the calculation of demand charges based on a 24 hour contract demand; the provision for year-round authorized overrun service; the accommodation of requests by customers for multiple delivery points; and the administration of charges respecting unauthorized overrun of contract demand as directed by the Board.

(2) Decision E89038 dated May 3, 1989, approved a schedule of revised T-Service Regulations and Interruptible Rates (IT-Rates) 14, 24 and 34 for CWNG and NUL.

(A) Authorized Overruns of Contract Demand

In accordance with directions in Interim Order E88075 dated October 24, 1988, CWNG/NUL proposed that the Authorized Overrun Service would be available year-round, with such service to be made available in the winter months of November through April on an interruptible or best efforts basis. The Industrial Rate Intervenors (the IRI) took exception to the monthly demand charge applicable in the winter months and suggested that this charge be based on the monthly demand prorated to the number of days used.

The Board considered that the offering of the Authorized Overall T-Service would allow T-customers additional flexibility and therefore should attract a higher charge. The Utilities' proposal was therefore considered reasonable.

(B) Monthly Tolerance Limits for Gas Imbalances and Settlement Provisions

In spite of the Board's determination in Decision E89001 dated February 3, 1989 that there be a ±5% tolerance limit respect of gas imbalances and that the settlement provisions only apply for over (under) deliveries in excess of 5%, the Utilities' filed submission indicated the tolerance limits to be set at ±2.5%. The Board rejected the ±2.5% limit stating that no new or additional evidence had been adduced by the Utilities to support the ±2.5% limit.

(C) Unaccounted For Gas (UFG)

In response to a direction in Decision E89001, the Utilities filed certain proposals to reconcile the UFG in respect of

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T-customers. In essence, these procedures require the Utilities to submit in September of each year a forecast UFG percentage, based on a five year average experienced UFG percentage. This forecast would be charged to all T-customers commencing January 1 of the subsequent year and later reconciled with the actual UFG percentage. The difference between the actual and forecast UFG percentage would then be applied to each T-customer's deliveries and multiplied by the Gas Cost Recovery Rate to obtain a reconciliation for each T-customer.

The Utilities proposed to make these procedures effective January 1, 1987. The Board did not agree with the City of Calgary that making the effective date January 1, 1987 would be retroactive ratemaking since the impact of any such reconciliation is to reach back into the past and reconcile with actual data. Since the UFG for sales customers has been reconciled as part of the Deferred Gas Accounting and Reconciliation procedures, equitable treatment dictated that the UFG reconciliation for T-customers should also date back to January 1, 1987.

(D) Interruptible (IT) Rates

The Board considered the Utilities' requirement for a one-month notice might be too stringent and onerous in certain cases. The Board deemed that a notice period of up to one month be required subject to the availability of system capacity.

The IRI submitted that in spite of the IT-Service being of an inferior quality (as compared with firm service), its rate was more expensive than the one year firm T-Service Rate. The IRI therefore recommended that the price of IT-Rates should not exceed the cost of the least cost firm service (i.e. Rates 20 and 30 at 100% load factor). The Board considered the pricing of the IT-Rates was consistent with the Board's previous methodology where the price for a shorter term T-Service exceeded that of a longer term T-Service.

The Board noted that the IT-Service is desirable in that it would increase the overall system load factor since "valleys" in the system capacity would be filled. Should there be some shift from firm load at system peak times, the IT-load would effectively avoid capacity additions in the long run.

The Utilities' IT-Rates, as filed, were therefore approved by the Board.

(3) Interim Order E89100 dated October 31, 1989, issued pursuant to Section 50 of the Public Utilities Board Act, gave ex parte interim approval to Rate 50, CWNG/NUL's proposed load balancing service rate to transportation customers. This proposed rate was not cost based, as directed by the Board, due to system measurement resource constraints.

Several Intervenors stated at the hearing that they had had insufficient time to prepare adequate representation on the matter. However, no Intervenor objected to the proposal that the Board issue an order fixing the load balancing rates as filed on an interim basis, on the proviso that they might later request a hearing into those rates.

(4) Decision E89066 dated November 7, 1989, fixed and approved Intervenors' costs and Applicants' external costs respecting the Transportation Rate 13 proceedings in the amount of $347,237.06 ($307,776.18 re Intervenors' costs and $39,460.88 re CWNG/NUL's external costs).

The approved costs were in accordance with the amounts submitted. The Board noted that the costs in question were incurred prior to the Board's May 24, 1989 "Scale of Costs" and therefore did not meet the guidelines set out therein. The Board concurred that costs should be awarded in respect of Rate 13 proceedings inasmuch as the issues raised pertained to the Phase II portion of NUL 1987/1988 GRA. The Board noted that the matters before it were complex, and involved several new issues (multiple cost of service studies and new transportation rates). The Board further noted that the Rate 13 proceedings accounted for about 39% of the total Phase II rate hearing costs.

(5) Order E89101 dated October 25, 1989 approved proposed Rate 12 (T-service to industrial customers who use Rate 2, the optional General Sales Service Rate) and Rate 41 (to industrial end-users currently taking sales service) on an interim refundable basis, effective on transportation or consumption on and after November 1, 1989.

The Board, by letter dated July 20, 1989, advised all parties to review the responses to information requests submitted in respect of the July 6, 1989 Application and if any party was not satisfied with these responses, it should request the Board to hold a hearing. In its September 18, 1989 letter to all parties, the Board noted that none of the parties had requested a hearing and accordingly, the Board proceeded to set dates for Argument and Reply.

Upon a review of filed evidence and argument, the Board noted that there were significant differences in the positions taken by the Utilities and Intervenors respecting some very fundamental aspects of the proposed Buy-Sell Rate 41. These differences in positions relate to the following issues: (1) eligibility, (2) use of appropriate load factor for gas delivery, (3) the annual quantity to be delivered, (4) the appropriate "buy" price and (5) quantum of penalties for failure of supply. In view of these differences, the Board submitted it was not in a position to approve, deny or amend the proposed Rates 41 and 12.

Recognizing that a hearing would be required to deal with the significant differences respecting

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the positions taken by the intervenors and CWNG/NUL (particularly in reference to the proposed Rate 41), and considering that customers may want to receive service beginning November 1, 1989, the Board approved the proposed Rates 12 and 41 on an interim basis.

5.17 (a) **Canadian Western Natural Gas Company Limited / Northwestern Utilities Limited**
RE89076 / RE89079 / C4.7.35-87 / C4.14.35-81

(b) An application by Esso Resources Canada Limited (ERCL), requesting the Board to amend or clarify the Deferred Gas Account (DGA) and reconciliation procedures for NUL and CWNG so as to:
(1) establish reasonable dates by which forecast gas price contractual rates shall be settled or be deemed settled, or
(2) establish reasonable dates by which the utilities' gas costs shall be finalized or deemed finalized for the purpose of affecting the reconciliation of the DGA for a prior season and for settling customer responsibilities for past gas costs.

(c) In Order C89047 dated November 9, 1989, the Board denied ERCL's application, stating that the lack of agreement between the two parties was not due to the DGA and reconciliation procedures, but instead due to the differing opinions of the value of the natural gas delivered under the ERCL contract, which requires yearly price redetermination.

5.18 (a) **ICG Utilities (Alberta) Ltd.**
RE87007 / RE87084 / E4.15.35-36 / E4.15.35-40

(b) For approval of a reduction in its rates, tolls and charges.

(c) Order E89045 dated May 3, 1989 approved as final rates, effective for all gas consumed on and after May 3, 1989, those interim rates approved in Order E87081 dated August 31, 1987, as amended by Order E88050 dated June 6, 1988 and Order E88056 dated July 5, 1988.

5.19 (a) **ICG Utilities (Alberta) Ltd.**
RE87013 / E4.15.35-37

(b) For approval of interim transportation service rate schedules for 1, 2, 3 and 5 year terms as directed by the Board in Order E86111 dated December 30, 1986.

(c) Interim Order E89044 dated May 3, 1989, approved the transportation service rate schedules as interim rates effective May 3, 1989.

5.20 (a) **ICG Utilities (Alberta) Ltd.**
RE89029 / RE89030 / E4.15.35-43 / E4.15.35-44

(b) For approval of a change in rates relating to the Village of Morrin and the Village of Hay Lakes because of changes in the revenue tax rates.

(c) Approved / E89051 dated May 24, 1989.

5.21 (a) **ICG Utilities (Alberta) Ltd.**
RE89102 / E4.15.35-45

(b) For approval of a change in rates for the 1989 and 1990 test years.

(c) In process at year end.

5.22 (a) **Northwestern Utilities Limited**
RE86052 / E4.14.35-49

(b) Application by Amoco Canada Petroleum Limited (Amoco) for an Order or Orders requiring NUL to provide restrictive transportation service to Amoco in the Pembina Cardium field.

(c) In Interim Order E86065, dated September 29, 1986, the Board directed NUL to provide Amoco restrictive service transportation for 171 x 10^3m^3/day of solution gas at rates specified in Rate 10 from Receipt Points to the Delivery Point in the Pembina Cardium field on an interim basis until such time as the Board has issued a policy order with respect to transportation and given effect to that policy.

By Decision E89078, dated August 29, 1989, the Board ordered:

(1) NUL provide transportation service to Amoco from the Receipt Points to the Delivery Point, all as set out in Order E86065, for a volume of gas nominated by Amoco and accepted by NUL and for a period of one, two or three years, at Amoco's option.

(2) The commencement date of the transportation service described in (1) above shall be October 18, 1986, the date upon which NUL first transported gas pursuant to Interim Order E86065.

(3) The rate to be charged by NUL to Amoco for the transportation service described in (1) above shall be whichever of NUL Rates 31, 32 or 33 that correspond to the term of service selected by Amoco.

5.23 (a) **Northwestern Utilities Limited**
RE86102 / E4.14.35-52

(b) Application by Texaco Canada Resources (TCR) for an Order or Orders requiring NUL to provide restrictive transportation service to TCR in the Pembina Cardium field.

(c) In Interim Order C86037, dated December 17, 1986, the Board directed NUL to provide TCR transportation of Cardium solution gas to the Cynthia Gas Plant operated by TCR from various receipt points in the Pembina oil field as specified in the application at Northwestern's Rate No. 10 (as approved by the Board from time to time) for the period from December 1, 1986, on an interim refundable basis until such time as the Board has issued a policy order with respect to gas transportation and given effect to that policy.

By Decision E89079, dated August 29, 1989, the Board ordered that:

(1) NUL provide transportation service to TCR from the Receipt Points to the Delivery Point, all as set out in Order C86037, for a volume of gas nominated by TCR and accepted by NUL and for a period of one, two or three years, at TCR's option.

(2) The commencement date of the transportation service described in (1) above shall be December 1, 1986, the date upon which NUL first transported gas pursuant to Interim Order C86037.

(3) The rate to be charged by NUL to TCR for the transportation service described in (1) above shall be whichever of NUL Rates 31, 32 or 33 that correspond to the term of service selected by TCR.

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5.24 (a) **Northwestern Utilities Limited**
RE86106 / E4.14.35-53

(b) Application by Esso Resources Canada Limited (ERCL) for an Order or Orders requiring NUL to provide restrictive transportation service to ERCL in the Pembina Cardium field.

(c) In Interim Order E86118, dated December 23, 1986, the Board directed NUL to provide ERCL transportation of solution gas to the point of Nova's intercept with the Pembina deliveries at NW17-47-9-W5M from the ERCL receipt point in the Pembina field as specified in the Application, at Northwestern's Rate No. 10 (as approved by the Board from time to time) for the period from December 1, 1986, on an interim refundable basis until such time as the Board has issued a policy order with respect to gas transportation and given effect to that policy.

By Decision E89080, dated August 29, 1989, the Board ordered that:

(1) NUL provide transportation service to ERCL from the Receipt Points to the Delivery Point, all as set out in Order E86118, for a volume of gas nominated by ERCL and accepted by NUL and for a period of one, two or three years, at ERCL's option.

(2) The commencement date of the transportation service described in (1) above shall be December 1, 1986, the date upon which NUL first transported gas pursuant to Interim Order E86118.

(3) The rate to be charged by NUL to ERCL for the transportation service described in (1) above shall be whichever of NUL Rates 31, 32 or 33 that correspond to the term of service selected by ERCL.

5.25 (a) **Northwestern Utilities Limited**
RE87065 / E4.1.14.35-66B

(b) For approval of a change in the existing rates, tolls and charges for natural gas supplied and services rendered to its customers within Alberta for the 1987 and 1988 test years.

(c) (1) General

(A) Order E89002 dated February 3, 1989, fixed the amount of Intervenors' costs and NUL's external costs relating to the Phase I proceedings.

Intervenors' costs were approved in the amount of $296,971.64. The intervention of Building Products of Canada Limited and Husky Oil Limited (BP/Husky) was related primarily to clarification of issues related to the Deferred Gas Accounting (DGA) and Reconciliation procedures and was of a nature that did not help the Board in its deliberation; hence, the Board disallowed the claim of BP/Husky for costs in the amount of $4,394.45. The Board approved the cost claim of Edmonton except for steno fees of $271.85 for Dr. Allan and Dr. Flock. Accordingly, while the costs claimed by all intervenors amounted to $301,637.94, the Board approved a total of $296,971.64.

NUL's total external cost claims were $159,285.76. In the exercise of the discretion allowed under Section 60 of the Public Utilities Board Act, the Board reduced the costs claimed by NUL for the following parties for a number of reasons. Costs submitted by Coopers & Lybrand on behalf of a Mr. Castaneda were reduced by $47.00, representing one half hour charged at $110.00/hr. Mr. Castaneda had all his other hours charged out at $40.00/hr. Nesbitt Thomson Bongard Inc. costs were reduced by $10,822.00 because no analysis was provided in respect of the relative amount of work undertaken by Mr. Chartrand and Ms. Schumacher. Further, while Mr. Chartrand appeared as a witness, the Board noted there was no evidence respecting the extent of Ms. Schumacher's involvement. Foster Associates, Inc. costs were reduced by $1,320.00 to reflect some duplication in costs in that Ms. McShane was required to attend the hearing in her capacity as Dr. Sherwin's replacement. Further, the Board disallowed secretarial and clerical fees of $1,978.39; and Costs submitted by Bennett Jones on behalf of Mr. Romanow were reduced by $4,247.86 to reflect Board findings that Mr. Romanow's role was primarily that of a counsel in training.

The Board accordingly approved external cost claims for NUL in the amount of $140,870.51, which is $18,415.25 less than the amount requested.

The Board approved the participants' costs respecting the proceedings related to the Deferred Gas Accounting and Reconciliation procedures for NUL and CWNG in amounts of $5,865.62 and $14,310.11, respectively.

The Board also made the following general comments on costs incurred by intervenors or parties to a Board proceeding.

Counsel is responsible for the delineation of issues and the elimination of extensive and unnecessary treatment of matters of marginal value to the Board in its determination of the merits;

The cost of retention of consultants and their support staff by counsel for educational purposes seems remote from costs incidental to proceedings before the Board;

Where a substantial professional fee is charged by a consultant for preparation to give evidence, the inclusion of various office overheads and hours spent by support staff falls in the area of marginal claims;

Future claims for costs of consultants are to be accompanied by a letter of retainer which identifies the scope of the assignment for which the consultant is engaged along with an identification of the specific issues to be addressed.

Counsel and or the consultant should be able to explain to the Board or its taxing

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officer where and in what way his services assisted the Board in its determination.

(B) Phase II Decision E89001 dated February 3, 1989 dealt with NUL's May 31, 1988 Phase II filing of its cost of service (COS) studies and the proposed schedule of rates, tolls and charges to recover NUL's non-gas component of its 1988 revenue requirement of $195,303,000 as determined by the Board in Phase I Decision E88018 dated March 18, 1988.

(C) Interim Order E89025 dated April 4, 1989 denied NUL's application for interim rates following the issuance of Phase II Decision E89001. The Board concluded there was no compelling or urgent reason why interim rates should be granted, as it was expected that final rates would be effective by June 1, 1989.

NUL's concern respecting Rate 1 customers experiencing a rate shock could be mitigated by extending the duration of the rate rider. NUL had also proposed certain changes to transportation terms and conditions of service and certain concerns were raised about the appropriate franchise tax rate applicable to the University. The Board considered these matters should be finalized only upon hearing all of the evidence and argument related thereto. Further, NUL's financial integrity would not be in jeopardy by denying the interim application for even if the revenue deficiency were not all collected in 1989, NUL would still accrue the uncollected balance.

(D) In Decision E89035 dated May 3, 1989 the Board finalized NUL's rates, tolls and charges and Natural Gas Transportation and Sales Service Regulations effective for all consumption on and after May 1, 1989.

(E) In Decision E89060 dated June 29, 1989, the Board approved for the stub period January 1, 1989 to April 30, 1989, NUL's calculations and method of refunding (collecting) the revenue surplus (deficiency) for the 1989 stub period. In general, the rate adjustment was determined by applying the differences between the final rates (effective May 1, 1989) and the rates in place during the 1989 stub period to the actual billing units over this period. For customers in Rates 1 and 2, the rate adjustment was calculated on a group basis and collected from these customers over the period July 1, 1989 to April 30, 1989.

(F) Decision E89066 dated November 7, 1989 fixed the amount of Intervenors' costs and the applicant's external costs respecting the Phase II proceedings. The Board approved for payment by NUL a sum of $552,626.21 ($472,965.06 re Intervenors' costs and $79,661.15 re NUL's external costs). The approved costs were in accordance with the amounts submitted. The Board noted that the costs in question were incurred prior to the Board's May 24, 1989 "Scale of Costs" and therefore did not meet the guidelines set out therein.

(2) Cost of Service (COS) Studies

(A) General

Nine different COS studies were presented in support of the proposed rates. COS No. 1 presented the traditional approach which adopted the Modified Seaboard method and functionalized costs to four categories (General, Gas Supply, Transmission and Distribution). COS Studies 2 through 9 expanded the functional categories to nine to include Administration, Marketing, Customer Accounting, Gas Management, Gas Supply, Production, Gathering, Transmission and Distribution.

(B) The Traditional Cost of Service Study (COS No. 1)

Under the Traditional COS approach, the totals allocated to customer, commodity and demand are distributed to rate classes in proportion to either the number of customers, throughput or demand of the rate class. The Board concurred with the Industrial Rate Intervenors (the IRI) that under this method, certain indirect overheads related to gas supply and distribution costs were assigned to transportation (Rate 10) customers (T-customers) even though these customers did not give rise to the related direct costs. The Board also considered that customer accounting costs should be distributed to T-customers without reference to their throughput.

(C) Cost of Service Studies Numbers 2-9

With respect to the eight COS studies (Numbers 2-9), the following four different costing methodologies were employed to allocate transmission and related costs (allocations to demand and energy in brackets): Modified Seaboard (75:25), Seaboard (50:50), United (25:75) and Fixed Variable (100:0). NUL tested its proposed rates against the averages obtained from all the COS studies. However, no preference was indicated for any one COS study.

The Board noted that under the multiple COS study approach, the costs distributed to Rates 1 and 10 experience a swing of $6.9 million (6.61%) and $7.4 million (23.8%) respectively. The Board noted that the average of costs assigned to each rate class does not reflect the costs caused by each rate class and expressed concern with an approach that blends the results of widely varying costing methodologies. While the results of different costing methodologies are important, the onus remains with NUL to demonstrate and determine which COS study best reflects the allocation of the underlying costs to be assigned to each rate group.

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(D) Gathering System Costs

In its previous COS studies, NUL functionalized all gathering costs as part of the Gas Supply category and allocated 100% to commodity (ie. all to sales customers). NUL proposed in the current Application to allocate such costs to both demand and commodity, consistent with the method of allocating transmission and related costs. Noting that only 3% of T-customers' volumes actually move through the gathering system, the Board considered it unfair to accept NUL's proposal. NUL was directed to allocate gathering system costs as it had done in its previous COS studies (ie. 100% commodity and to sales customers only). To the extent T-customers do use the gathering system to source their gas, the Board directed NUL to file an appropriate unbundled rate. Revenues from such a rate would be considered as income credits.

(E) Salt Cavern Storage Costs

As with the gathering system costs, NUL allocated the salt cavern costs based on transmission costs whereas in the previous COS studies these costs were shown as part of the gas supply function (i.e. allocated 100% to sales customers). The Board noted that the caverns served the peak day requirements of both the sales and transportation customers.

The caverns have effectively displaced the transmission lines that would otherwise be required, in which case the costs would have been assigned to all customers. The caverns also allow the flexibility of accommodating alternate gas supply sources to the sales customers requirements. Further, they also assist in maintaining pressure requirements without which NUL could not supply the required delivery pressures to the high pressure T-customers.

While NUL's proposal was accepted, the Board directed that since T-customers do not purchase any gas supplies from NUL, the assignment of storage costs using their throughput as an allocator was inappropriate. NUL should therefore refile its COS study such that costs are distributed to Rate 10 by assuming a nil throughput for Rate 10 customers.

(F) Production Costs

In prior COS study filings, NUL had allocated production costs as 100% commodity. In the current Application, such costs were allocated 75:25 to demand:commodity since production chases load and winter production volumes are some 8 to 10 times greater than summer volumes on a monthly basis. On examination of the production pattern, the Board noted that monthly production varied widely by month and by season and did not demonstrate why a 75:25 demand:commodity split was justified. NUL was directed to allocate all production costs as 100% commodity related.

(G) Revenue Cost Ratios

NUL proposed to widen the tolerance limit from ±5% to ±10% since the latter would yield the same arithmetical results as ±5% applied to the gas and non-gas components of the revenue requirement.

The Board noted that when gas prices were regulated, the price changes were passed on to the customers. Hence, other than a reconciliation of actual vs forecast gas costs that now takes place, circumstances in respect of gas costs have not changed materially to warrant a widening of the tolerance limits.

(3) Service Classification - Integrated Transportation System

The Municipal Intervenors (MI) argued that inasmuch as transportation services are purchased by all customers, transportation is provided on the entire integrated system and therefore distinctions between gathering, transmission and distribution systems are irrelevant. Rolling in the transmission and distribution system costs would result in an increase in costs assigned to Rate 10 customers of about $16.2 million and a decrease to Rate 1 customers of about $13.2 million.

While the system may be considered integrated in that there is no attempt to trace the gas molecules once in the system, the Board considered that the costs of production, distribution, transmission, etc., should be allocated to such functions and assigned, to the extent possible, to the customers who cause such costs. The Board also expressed concerns respecting the significant swing in costs assigned to Rates 1 and 10 as a result of rolling in transmission and distribution costs.

(4) Specific Proposals for Rates, Tolls and Charges

(A) Rate 1 Fixed Charges

Based on the fixed charges of other utilities across Canada, Edmonton submitted NUL's proposed Rate 1 monthly fixed charge of $9.75 appeared too high and would encourage consumption while discouraging conservation. Edmonton took the mid point and average of the fixed charges of those utilities and recommended a monthly charge of $7.50. Edmonton's recommendation would result in a recovery of about 54% of the total customer costs assigned to Rate 1. To recover 100% of such costs, the fixed charge would amount to $13.93, a charge the Board noted would not find customer acceptance based on the current and historical levels of Rate 1 fixed charges.

A recovery of 54% was considered too low since it went directionally against the

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objective of matching costs to revenues. Since the proposed charge of $9.75 recovers about 65% of customer costs, the Board approved this charge and directed NUL to maintain in its future filings, a recovery of at least 65% of customer related costs in the Rate 1 fixed charge.

(B) Rate 3

NUL proposed the measurement of billing demand be based on the maximum usage over a 24 hour period, as opposed to the current 12 hour period, since the costs have been distributed based on a 24 hour demand. Each Rate 3 customer, therefore, would be charged a demand rate that is proportional to the demand costs. While the total revenues to NUL from the billing demand component of Rate 3 would not change, the Board noted that individual customers may experience a change in their costs. Should such customers be affected in a material way as a result of this change, the Board considered they should make known their concerns at the earliest possible date.

(C) Rates 5 and 7

The MI suggested Rate 5 (Sales to Other Distribution Companies) be cancelled and customers in this rate take service from Rates 1, 2, 3 or 4. The MI noted that while there may be public policy reasons to maintain this rate and classification separately, no such reasons had been advanced. Respecting Rate 7 (Sales to Gas Alberta) the MI questioned why there were no demand related charges. The Board considered it appropriate to retain Rate 5 as a separate rate class and in its present form at this time. For Rate 7, the Board noted that the proposed rates would recover the exact amount of costs assigned to this rate. Accordingly, no changes were necessary. However, NUL was directed to address the merits of designing a Rate 7 that contains both a demand and energy charge.

(D) Service Regulations

The Board expressed concern that NUL's interpretation of item 4.6(a) of its Regulations appears to preclude a new customer from establishing a satisfactory credit rating without incurring some cost of a guarantee (security deposit, bond or letter of credit). Considering this interpretation to be contrary to the intent and spirit of item 4.6(a) of NUL's Service Regulations, the Board directed it to file, at its next GRA, an amendment such that new customers may have the opportunity to establish credit without cost.

(5) University of Alberta

While both the University of Alberta and the Edmonton Power Rossdale plant are being served off the same line, the line serving Rossdale is deemed a transmission line whereas that line serving the University is considered a distribution line. However, the line serving the University has characteristics of a transmission line in that it is a 12 inch line operating at a pressure of 300 psi. Further, the University's consumption represents about 9% of the total Rate 2 consumption and is almost one hundred times the average of Rate 2 customers. Its load factor of 40% is also greater than the average Rate 2 load factor of 33%.

The Board therefore agreed the University should not be classed as a Rate 2 customer. While the University could take service from other rates, for which there are no distribution costs (Rates 4, 6 and 7), the Board considered that none of these rates would suit the University. NUL was therefore directed to file a three-part rate that specifically recognized the unique characteristics and costs caused by the University.

Respecting the franchise tax it should pay, the majority of the Board considered that a case may be made to support the contention that franchise tax cannot be imposed so as to create rates which are discriminatory as between classes or consumers within a class. Since the Board directed NUL to file an appropriate rate for the University, the Board noted that the University might wish to negotiate with Edmonton a new franchise tax rate and have the amended agreement brought before the Board. For further information in this regard, see Section (14).

(6) Unbundled Transportation Service

(A) Storage

The availability and security of gas supplies at peak times was considered by the Board to be necessary and critical for all customers. Because of the slow-fill characteristics of the caverns, unlimited access would impose a risk on all customers in the event of a draw-down on storage. Accordingly, storage as an unbundled service was denied.

(B) Gathering

The Board considered that an appropriate unbundled rate should be designed for those T-customers who use the gathering facilities.

(C) Load Balancing Costs

The Board noted that customers are willing to pay for a load balancing service based on the basis of a known and quantifiable source of gas (such as spot gas). The Board considered that CWNG/NUL should carry out studies on selected industrial customers to identify and quantify load balancing costs caused by such customers. Therefore, CWNG/NUL were directed to provide a load balancing service as an optional unbundled service to be effective November 1, 1989 and file a cost based rate by September 30, 1989.

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(7) Canfor's Hines Creek Plant

Canfor submitted that while it is being served off a 2 inch high pressure transmission line (which connects to a 4 inch transmission line), it gets assigned distribution costs even though it does not use the related distribution facilities.

Canfor takes service under Rate 3. The Board noted that if Canfor had a consumption in excess of 300,000 GJ, it would be entitled to be under Rate 4 and not pay any distribution costs. The Canfor plant was considered typical by the Board in that there are several customers who, while being classified as Rate 3, are served off the transmission line or are attached to the transmission line by a stub transmission line. The Board noted that under the postage stamp concept, customers in a particular rate group should share the average costs assigned to that class. Accordingly, Canfor's submission was denied.

(8) High Pressure Surcharge

Based on the current throughput of those T-customers taking service at higher than normal pressures, the Board estimated that the revenue requirement to serve those customers was about $1.8 million. Further the Board determined that the current incremental cost of the high pressure facilities was about $2.3 million. The Board therefore considered the current level of high pressure surcharge rate yielding revenues of about $2.2 million to be reasonable.

(9) Lost and Unaccounted for Gas

The Board considered that a calculation of line loss should be based on a five year average using a 12 month period ending December 31. For T-customers, the Board approved NUL's proposed reconciliation of actual to the forecast line losses and directed it file such a reconciliation commencing from January 1, 1987.

(10) Buy - Sell Service

The Board noted that CWNG/NUL have a portfolio of gas supply and various sources of gas supply are used for load balancing purposes. The Board considered the average cost of load balancing is already included in the gas component of the sales rates. Under a market oriented pricing system, if an industrial user can directly obtain his gas supply requirements at a lower price than the utilities can purchase, the Board considered it reasonable to expect the utilities to buy such gas from the end-user and continue to serve him as a sales customer. The price to be paid by the utilities (to the end-user) shall be equivalent to the average cost of gas purchased under long term contracts subject to arbitration.

(11) Recovery of Municipal Franchise Tax

The City of Calgary contended that the provisioning of T-service could erode the franchise tax base since the total amount paid by a T-customer would not be included in the utility's gross revenue from the sale of gas. The Board considered it premature to deal with this matter at this time. While this matter may have to be resolved by the parties to the franchise agreements and/or by changes to existing legislation, the Board will respond to such changes as they occur. If a municipality is affected by the decision of a sales customer to become a T-customer, the municipality is free to come to the Board for approval to amend its franchise agreement.

(12) Dissenting Opinion of Board Member R.D.S. Ward

Member Ward considered that the franchise tax collected under Section 14(7) of the Municipal Taxation Act should have some relevance to the assessed value of the property and assets used by the utility in the exercise of the franchise. Further, inasmuch as the collection of franchise tax is in reference to the gross revenues of the utility, such a method appears to be outside the authority granted by the legislators. Member Ward considered that the franchise tax should be collected, without discrimination, in reference only to the revenues obtained from the non-gas components of the utility's rates. In this way, the concern about discriminatory franchise rates would be addressed as well.

(13) Revised Cost of Service Study and Revised Rates, Tolls and Charges

On March 8, 1989, NUL filed a revised COS study reflecting the Board's determinations made in Decision E89001 in respect of the methods of cost allocation and distribution. NUL used this revised COS study to design rates that resulted in a revenue:cost ratio of close to unity for all rate classes. The result of such a "mechanical" application was that when compared with the existing rates, Rates 1 and 2 received about a 13-14% rate increase whereas the transportation rates would experience a 9% decrease.

Except for a general direction to observe a ±5% tolerance with respect to the revenue cost ratios, the majority of the Board did not consider Decision E89001 gave any explicit directions to NUL as to how it should design rates once the costs were distributed to rate classes. The majority felt that rate design has always been an art requiring some sound knowledge and judgement or a balancing act that has to

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be undertaken by the utility for review by the Board and Intervenors. Further, a COS study is only one criterion, amongst several, that should be used to determine whether the rates are just and reasonable.

Member A.C. Barfett expressed the view that the rates, tolls and charges filed by NUL were in compliance with Board Decision E89001 and reflected the allocation and distribution of costs provided therein.

Notwithstanding these concerns, the Board considered that the "stability of rates" criterion had been achieved for Rate 1 customers once gas costs were accounted for. The rate increase to these customers was effectively halved to 7% with gas costs. Further mitigating the proposed rate increase to the Rate 1 class was the decision by the Board to extend the collection of the revenue deficiency from December 31, 1989 to April 30, 1990.

(14) University of Alberta Special Contract Rate

In response to Decision E89001, NUL proposed a Special Contract Rate designed to meet the special characteristics of the University of Alberta (the University). This rate would attract a franchise rate of 11.11%, similar to that for the low load factor sales customers. The University advised that it may not take this rate, but instead opt for Rate 4 effective November 1, 1989. While the University requested the Board rule that the Special Contract Rate should attract the lower franchise rate of 2.04%, the Board considered there was no reason to make such a ruling at this time respecting the appropriate franchise rate. Should the University avail itself of this Special Contract Rate, it should provide to the Board the results of its discussions with the City of Edmonton respecting its negotiations to strike the lower franchise rate.

(15) Rate 13

The Board found that the derivation of Rate 13, approved initially on an interim basis in Order E88075 dated October 24, 1988, was consistent with the determinations made in Decision E89001 respecting the assignment or distribution of costs to this rate.

(16) Natural Gas Regulations

In Decision E89035, the Board approved NUL's natural gas sales regulations which were amended to reflect determinations made in Decision E89001.

5.26 (a) **Northwestern Utilities Limited**
RE89011 / RE89053 / E4.14.35-76 / E4.14.35-78
(b) For approval of a change in rates relating to the Town of Coronation and the Town of Drayton Valley because of changes in the revenue tax rates.
(c) Approved / E89065 dated July 5, 1989.

5.27 (a) **Northwestern Utilities Limited**
RE89015 / E4.14.35-77
(b) For approval of a revised Gas Cost Recovery Rate (GCRR) for the summer period from April 1, 1989 to October 31, 1989 inclusive and a reconciliation of the actual gas costs with the actual gas cost recoveries for the prior summer period (April 1, 1988 to October 31, 1988 inclusive).
(c) In Order E89019 dated April 4, 1989, the Board approved a one cent/GJ increase to the previously approved summer GCRR of $1.184/GJ, fixed in E88037 dated March 29, 1988.

With respect to the over collections held in the Deferred Gas Account (DGA), NUL took the position that no interest should be attached to such over collections since (i) they are insignificant compared to the overall cash flows; (ii) a General Rate Application, when all other cash flows are examined, would be the more appropriate forum to deal with the interest issue and (iii) NUL was anticipating some gas supply rebates from the Provincial Government that would offset the over collections. NUL also submitted that a three to four year period rather than a six month period, be considered to determine whether the over(under) collections have been persistent. Further, the Board should accept a range of ±4% to ±5%, of the total annual gas supply costs, as a reasonable tolerance limit for the over(under) collections held in the DGA.

The Board considered, based on the evidence presented, that NUL's forecast of its 1989 summer GCRR of $1.194/GJ was reasonable. However, inasmuch as NUL's negotiations with its long-term producers and other suppliers had not been completed, the Board expected that NUL would advise the Board of the settlements as soon as possible.

5.28 (a) **Northwestern Utilities Limited**
RE89059 / E4.14.35-79
(b) For approval of a change in rates relating to the University of Alberta because of a decrease in the revenue tax rate from 11.11% to 2.04%.
(c) Approved / E89077 dated September 1, 1989.

5.29 (a) **Northwestern Utilities Limited**
RE89065 / E4.14.35-80
(b) For approval of the Board to change Rate Rider "A" to include Jasper by fixing the municipal tax rate at 5.25% to be applied as an addition to customer rates within the Jasper area.
(c) Decision E89102 dated October 31, 1989 approved the application effective December 1, 1989.

5.30 (a) **Northwestern Utilities Limited**
RE89082 / E4.14.35-82
(b) For approval of a change in rates relating to the City of Fort McMurray due to an increase in the revenue tax rate from 4.17% to 8.7%.
(c) Approved / E89083 dated September 8, 1989.

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5.31 (a) **Northwestern Utilities Limited**
RE89087 / E4.14.35-83
(b) For a change in its winter season Gas Cost Recovery Rate (GCRR) effective November 1, 1988 and a change in its Rider "D" for collection of unaccounted for gas costs effective January 1, 1990.
(c) In Interim Order E89098 dated October 31, 1989, the Board approved NUL's application, stating that the calculations and forecasts NUL used to derive the 1990 calendar year Rider "D" of 1.4% and the 1989/90 winter GCRR of $1.469/GJ (the 1988/89 winter GCRR had been $1.323/GJ), were reasonable. The Board also approved the new Rider "D" rate and rate schedules to reflect the higher winter GCRR, that NUL proposed. The new Rider "D" schedule was not attached to the original order, but an amending letter dated November 7, 1989 corrected that omission.

5.32 (a) **Northwestern Utilities Limited**
RE89098 / E4.14.35-84
(b) For approval of a change to Rate Rider "A" for the listing for the Town of Peace River.
(c) In process at year end.

5.33 (a) **Northwestern Utilities Limited**
RE89106 / E4.14.24(1)(e)-30
(b) For an Order approving the purposes of, and authorizing the issue of 10.20% Debentures 1989 Series to Canadian Utilities Limited in the principal amount of $20,000,000.
(c) Order E89119 dated December 22, 1989, approved the issue and the purposes of the issue.

5.34 (a) **Orr Mineral Developments Ltd.**
RE88041 / E4.16.35-8
(b) For approval of an increase in rates for the Hamlet of Suffield.
(c) Order E89104 dated November 1, 1989 approved an increase in rates for the Company. The Board's detailed reasons for this increase were pending at year end.

Section 6: Utilities Not Offering Utility Services to the General Public

Data reported in groups arranged alphabetically according to the name of the regulated utility to which the application refers. Individual applications within each group are then arranged in order of registration number.

ITEM NUMBER — APPLICATION PARTICULARS
(a) REGULATED ENTITY / REGISTRATION NUMBER / FILE NUMBER
(b) SUBJECT MATTER
(c) DISPOSITION / REFERENCE

6.01 (a) **Atco Utilities Holdings Ltd. / Canadian Utilities Limited**
RC89046 / C4.4095.3(1)(c)-2 / C3.504.70.1(1)(c)-2
(b) (1) Application by Atco Utilities Holdings Ltd. for an Order of the Board declaring that Section 91.1(2)(d) of the Public Utilities Board Act and Section 25.1(2)(d) of the Gas Utilities Act do not apply to the Applicant with respect to a certain transaction.
(2) Application by Canadian Utilities Limited for an Order of the Board declaring that Section 91.1 of the Public Utilities Board Act and Section 26.1 of the Gas Utilities Act do not apply to the Applicant with respect to a certain transaction.
(c) (1) Approved / C89041 dated August 14, 1989.
(2) Approved / C89042 dated August 14, 1989.

6.02 (a) **Dome Petroleum Limited, on behalf of itself and its wholly-owned subsidiary, Hudson's Bay Oil and Gas Company Limited**
RC89022 / E4.306.3(1)(c)-8 / E4.311.3(1)(c)-2
(b) For an Order of the Board declaring that, for the purposes of certain transactions, the provisions of Section 99 of the Public Utilities Board Act, and Sections 50 and 51 of the Gas Utilities Act to the extent that they incorporate Section 99 of the Public Utilities Board Act, do not apply to the Applicants.
(c) Approved / E89022 dated March 30, 1989.

6.03 (a) **Imperial Oil Limited and Certain Imperial Related Corporations**
RC89008 / C3.563.70.1(1)(c)
(b) For an Order declaring that, for the purposes of a certain transaction, the provisions of Section 99 of the Public Utilities Board Act, and Sections 50 and 51 of the Gas Utilities Act, to the extent that they incorporate Section 99 of the Public Utilities Board Act, do not apply to the Applicants.
(c) Approved / C89004 dated February 16, 1989.

6.04 (a) **Inter-City Gas Corporation**
RC89038 / C4.2104.25.1(4)
(b) For an Order pursuant to Section 91.1(4) of the Public Utilities Board Act and Section 25.1(4) of the Gas Utilities Act declaring that, for the purposes of certain transactions, the provisions of Section 91.1(2)(d)(i) of the Public Utilities Board Act and Section 25.1(2)(d)(i) of the Gas Utilities Act do not apply to the Applicant.
(c) Approved / C89027 dated June 6, 1989.

6.05 (a) **Pinnacle Resources Ltd. / Trigas Exploration Ltd. / 355882 Alberta Inc.**
RE89097 / E4.4625.3(1)(c) / E4.4626.3(1)(c) / E4.4627.3(1)(c)
(b) For an Order declaring that, for the purposes of certain transactions, the provisions of Section 99 of the Public Utilities Board Act, and the provisions of Section 99 of the Public Utilities Board Act to the extent that it may be incorporated into the Gas Utilities Act by operation of Sections 50 and 51 of the Gas Utilities Act, do not apply to the Applicants.
(c) Approved / C89049 dated November 22, 1989.

6.06 (a) **Texaco Canada Inc. and 393437 Alberta Ltd. and Certain Texaco Related Corporations**
RC89007 / C3.562.70.1(1)(c)
(b) For an Order declaring that, for the purposes of a certain transaction, the provisions of Section 99 of the Public Utilities Board Act, and Sections 50 and 51 of the Gas Utilities Act, to the extent that they incorporate Section 99 of the Public Utilities Board Act, do not apply to the Applicants.
(c) Approved / C89003 dated February 16, 1989.

6.07 (a) **Trical Resources Inc. / Voyager Energy Inc.**
RC89054 / C3.564.70.1(1)(c) / C3.565.70.1(1)(c)
(b) For an Order declaring that, for the purposes of a

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certain transaction, the provisions of Section 99 of the Public Utilities Board Act do not apply to the Applicants.

(c) Approved / C89054 dated December 18, 1989.

6.08 (a) **Trical Resources Inc. / Voyager Energy Inc. / CanCapital Corporation / F.C. Financial Corp. / John F. Fleming**
RC89055 / C4.4623.3(1)(c)

(b) For an Order declaring that, for the purposes of certain transactions, the provisions of Section 99 of the Public Utilities Board Act, and the provisions of Section 99 of the Public Utilities Board Act to the extent that it may be incorporated into the Gas Utilities Act by operation of Sections 50 and 51 of the Gas Utilities Act, do not apply to the Applicants.

(c) Approved / C89055 dated December 19, 1989.

6.09 (a) **Ultramar Oil and Gas Canada Limited and Chauvco Resources Ltd.**
RC89056 / C4.4624.3(1)(c)

(b) For an Order declaring that, for the purposes of certain transactions, the provisions of Section 99 of the Public Utilities Board Act, and the provisions of Section 99 of the Public Utilities Board Act to the extent that it may be incorporated into the Gas Utilities Act by operation of Sections 50 and 51 of the Gas Utilities Act, do not apply to the Applicants.

(c) Approved / C89056 dated December 20, 1989.

Section 7: Municipalities

SECTION 7A:
Applications by municipalities, pursuant to the Municipal Government Act, for approval to enter into supply and special franchise agreements or renewals or alterations thereof with owners of utilities. Where the municipality agrees to accept a percentage of the gross revenue of the franchise holder in lieu of taxing the special franchise and property of the holder used in the exercise of the franchise pursuant to the Municipal Taxation Act, the amount of such percentage is reflected.

Data reported in groups arranged alphabetically according to the name of the regulated utility to which the application refers. Individual applications within each group are then arranged in order of registration number.

ITEM NUMBER — APPLICATION PARTICULARS
(a) APPLICANT / REGISTRATION NUMBER / FILE NUMBER
(b) SUBJECT MATTER
(c) DISPOSITION / REFERENCE

7.01 (a) **New Town of Rainbow Lake**
RE88075 / E6.90.3

(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to enter into a revenue tax agreement / **Alberta Power Limited** / based on an escalating percentage of gross revenue.

(c) Approved / E89030 dated April 12, 1989.

7.02 (a) **Village of Mannville**
RE88089 / E6.257.3

(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Alberta Power Limited** / based on an escalating percentage of gross revenue.

(c) Approved / E89029 dated April 12, 1989.

7.03 (a) **Town of McLennan**
RE89001 / E6.77.3

(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Alberta Power Limited** / based on an escalating percentage of gross revenue.

(c) Approved / E89028 dated April 12, 1989.

7.04 (a) **Village of Donnelly**
RE89005 / E6.205.3

(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Alberta Power Limited** / based on an escalating percentage of gross revenue.

(c) Approved / E89026 dated April 12, 1989.

7.05 (a) **Village of Donalda**
RE89006 / E6.204.3

(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Alberta Power Limited** / based on an escalating percentage of gross revenue.

(c) Approved / E89027 dated April 12, 1989.

7.06 (a) **Village of Nampa**
RE89009 / E6.267.3

(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Alberta Power Limited** / at a rate of 3%.

(c) Approved / E89042 dated May 10, 1989.

7.07 (a) **Village of Alliance**
RE89017 / E6.154.3

(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Alberta Power Limited** / at a rate of 3%.

(c) Approved / E89041 dated May 10, 1989.

7.08 (a) **Town of Hanna**
RE89019 / E6.51.3

(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Alberta Power Limited** / based on an escalating percentage of gross revenue.

(c) Approved / E89059 dated June 22, 1989.

7.09 (a) **Village of Kitscoty**
RE89021 / E6.248.3

(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Alberta Power Limited** / based on an escalating percentage of gross revenue.

(c) Approved / E89040 dated May 10, 1989.

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7.10 (a) **Town of Three Hills**
RE89023 / E6.111.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Alberta Power Limited** / based on an escalating percentage of gross revenue.
(c) Approved / E89058 dated June 22, 1989.

7.11 (a) **Village of Girouxville**
RE89024 / E6.224.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Alberta Power Limited** / at a rate of 5%.
(c) Approved / E89056 dated June 22, 1989, as amended by E89110 dated December 6, 1989.

7.12 (a) **Village of Innisfree**
RE89031 / E6.241.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Alberta Power Limited** / based on an escalating percentage of gross revenue.
(c) Approved / E89057 dated June 22, 1989.

7.13 (a) **Village of Rumsey**
RE89034 / E6.284.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Alberta Power Limited** / at a rate of 3%.
(c) Approved / E89070 dated August 16, 1989.

7.14 (a) **Village of Derwent**
RE89039 / E6.202.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Alberta Power Limited** / at a rate of 3%.
(c) Approved / E89069 dated August 16, 1989.

7.15 (a) **Village of Botha**
RE89040 / E6.174.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Alberta Power Limited** / based on an escalating percentage of gross revenue.
(c) Approved / E89071 dated August 16, 1989.

7.16 (a) **Town of Manning**
RE89049 / E6.75.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Alberta Power Limited** / to increase the franchise tax from 3.50% to 5.0%.
(c) Approved / E89073 dated August 16, 1989.

7.17 (a) **Village of Galahad**
RE89051 / E6.221.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Alberta Power Limited** / to increase the franchise tax from 2% to 3%.
(c) Approved / E89072 dated August 16, 1989.

7.18 (a) **Town of Fairview**
RE89054 / E6.50.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Alberta Power Limited** / at a rate of 5%.
(c) Approved / E89087 dated September 8, 1989.

7.19 (a) **Town of Trochu**
RE89064 / E6.113.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Alberta Power Limited** / based on an escalating percentage of gross revenue.
(c) Approved / E89092 dated October 25, 1989.

7.20 (a) **Village of Carbon**
RE89067 / E6.180.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Alberta Power Limited** / based on an escalating percentage of gross revenue.
(c) Approved / E89085 dated September 8, 1989.

7.21 (a) **Town of Grimshaw**
RE89071 / E6.60.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Alberta Power Limited** / at a rate of 5%.
(c) Approved / E89086 dated September 8, 1989.

7.22 (a) **Village of Delia**
RE89080 / E6.201.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Alberta Power Limited** / based on an escalating percentage of gross revenue.
(c) Approved / E89093 dated October 25, 1989.

7.23 (a) **Town of Valleyview**
RE89083 / E6.115.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Alberta Power Limited** / based on an escalating percentage of gross revenue.
(c) Approved / E89108 dated December 6, 1989.

7.24 (a) **Village of Hines Creek**
RE89096 / E6.236.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Alberta Power Limited** / based on an escalating percentage of gross revenue.
(c) In process at year end.

7.25 (a) **Town of Mundare**
RE89099 / E6.80.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Alberta Power Limited** / based on an escalating percentage of gross revenue.
(c) In process at year end.

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7.26 (a) **Village of Minburn**
RE89100 / E6.261.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Alberta Power Limited** / at a rate of 3%.
(c) In process at year end.

7.27 (a) **Town of Wembley**
RE89101 / E6.137.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Alberta Power Limited** / at a rate of 5%.
(c) In process at year end.

7.28 (a) **Village of Berwyn**
RE89103 / E6.165.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Alberta Power Limited** / based on an escalating percentage of gross revenue.
(c) In process at year end.

7.29 (a) **Village of Dewberry**
RE89104 / E6.203.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Alberta Power Limited** / based on an escalating percentage of gross revenue.
(c) In process at year end.

7.30 (a) **Village of Donalda**
RE89111 / E6.204.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Alberta Power Limited** / at a rate of 3%.
(c) In process at year end.

7.31 (a) **Village of Burdett**
RC88027 / E6.179.4
(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Canadian Western Natural Gas Company Limited** / at a rate of 5.26%.
(c) Approved / C89002 dated February 16, 1989.

7.32 (a) **Village of Cayley**
RC89004 / E6.184.4
(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Canadian Western Natural Gas Company Limited** / at a rate of 5.26%.
(c) Approved / C89006 dated March 5, 1989.

7.33 (a) **Village of Irricana**
RC89009 / E6.243.4
(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Canadian Western Natural Gas Company Limited** / at a rate of 5.26%.
(c) Approved / C89012 dated April 26, 1989.

7.34 (a) **Village of Barons**
RC89011 / E6.159.4
(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Canadian Western Natural Gas Company Limited** / at a rate of 5.26%.
(c) Approved / C89015 dated April 26, 1989.

7.35 (a) **Village of Beiseker**
RC89012 / E6.162.4
(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Canadian Western Natural Gas Company Limited** / at a rate of 5.26%.
(c) Approved / C89019 dated May 10, 1989.

7.36 (a) **Village of Carmangay**
RC89015 / E6.181.4
(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Canadian Western Natural Gas Company Limited** / at a rate of 5.26%.
(c) Approved / C89013 dated April 26, 1989.

7.37 (a) **Village of Hill Spring**
RC89018 / E6.235.4
(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Canadian Western Natural Gas Company Limited** / at a rate of 5.26%.
(c) Approved / C89018 dated May 10, 1989.

7.38 (a) **Village of Acme**
RC89020 / E6.151.4
(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Canadian Western Natural Gas Company Limited** / at a rate of 5.26%.
(c) Approved / C89020 dated May 10, 1989.

7.39 (a) **Village of Carbon**
RC89023 / E6.180.4
(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Canadian Western Natural Gas Company Limited** / at a rate of 5.26%.
(c) Approved / C89021 dated May 10, 1989.

7.40 (a) **Village of Champion**
RC89027 / E6.186.4
(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Canadian Western Natural Gas Company Limited** / at a rate of 5.26%.
(c) Approved / C89030 dated July 5, 1989.

7.41 (a) **Village of Glenwood**
RC89028 / E6.226.4
(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax

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agreement / **Canadian Western Natural Gas Company Limited** / at a rate of 5.26%.

(c) Approved / C89024 dated June 6, 1989.

7.42 (a) **Town of Strathmore**
RC89030 / E6.106.4

(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Canadian Western Natural Gas Company Limited** / at a rate of 5.26%.

(c) Approved / C89025 dated June 6, 1989.

7.43 (a) **Town of Vulcan**
RC89036 / E6.120.4

(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Canadian Western Natural Gas Company Limited** / at a rate of 5.26%.

(c) Approved / C89033 dated July 19, 1989.

7.44 (a) **Town of Stavely**
RC89040 / E6.102.4

(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Canadian Western Natural Gas Company Limited** / at a rate of 5.26%.

(c) Approved / C89034 dated July 19, 1989.

7.45 (a) **Town of Taber**
RC89048 / E6.110.4

(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Canadian Western Natural Gas Company Limited** / at a rate of 5.26%.

(c) Approved / C89048 dated November 22, 1989.

7.46 (a) **Town of Hanna**
RE89020 / E6.61.4

(b) For approval to enter into a natural gas supply contract and to confer a special franchise for the period until January 10, 1995 and to enter into a revenue tax agreement / **East Central Gas Co-op Ltd.** / at a rate of 3.1%.

(c) Order E89054 dated June 6, 1989 approved the application. The franchise agreement applies only to those residents of the area annexed to the Town on December 31, 1987 pursuant to Order in Council 82/88 dated February 18, 1988. Other residents are served by ICG Utilities (Alberta) Ltd.

7.47 (a) **Village of Hay Lakes**
RE88084 / E6.233.4

(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **ICG Utilities (Alberta) Ltd.** / at a rate of 5%.

(c) Approved / E89049 dated May 24, 1989.

7.48 (a) **Village of Morrin**
RE88086 / E6.263.4

(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **ICG Utilities (Alberta) Ltd.** / at a rate of 4%.

(c) Approved / E89050 dated May 24, 1989.

7.49 (a) **Village of Radway**
RE88087 / E6.278.4

(b) For approval to enter into a franchise tax agreement / **ICG Utilities (Alberta) Ltd.**

(c) Withdrawn by Applicant.

7.50 (a) **Summer Village of Grandview**
RE89002 / E6.228.4

(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years / **ICG Utilities (Alberta) Ltd.**

(c) Approved / E89048 dated May 24, 1989.

7.51 (a) **Town of Grande Cache**
RE89003 / E6.58.4

(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **ICG Utilities (Alberta) Ltd.** / at a rate of 6.952%.

(c) Approved / E89047 dated May 24, 1989.

7.52 (a) **City of Leduc**
RE89084 / E6.16.4

(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years / **ICG Utilities (Alberta) Ltd.**

(c) Approved / E89048 dated May 24, 1989.

7.53 (a) **Town of Calmar**
RE89088 / E6.32.4

(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **ICG Utilities (Alberta) Ltd.** / at a rate of 3.1%.

(c) In process at year end.

7.54 (a) **Village of Radway**
RE89090 / E6.278.4

(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **ICG Utilities (Alberta) Ltd.** / at a rate of 3%.

(c) In process at year end.

7.55 (a) **Village of Evansburg**
RE87064 / E6.214.4

(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Northwestern Utilities Limited** / at a rate of 5.26%.

(c) Approved / E89023 dated April 12, 1989. This Order amended Order E88028 dated March 17, 1988 which approved the entering into of the renewal of the special franchise agreement as filed with the Board with the Village's application. Order E89023 approved the entering into of the renewal of the subsequently executed special franchise agreement dated May 27, 1988 which differed from the initially filed agreement.

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7.56 (a) **Summer Village of Alberta Beach**
RE88027 / E6.152.4
(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Northwestern Utilities Limited** / at a rate of 5.26%.
(c) Approved / E89052 dated June 6, 1989.

7.57 (a) **Village of Chipman**
RE88059 / E6. 189.4
(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Northwestern Utilities Limited** / at a rate of 5.26%.
(c) Approved / E89017 dated March 22, 1989.

7.58 (a) **Village of Consort**
RE88068 / E6.103.4
(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Northwestern Utilities Limited** / at a rate of 5.26%.
(c) Approved / E89016 dated March 22, 1989.

7.59 (a) **Village of Onoway**
RE88085 / E6. 272.4
(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Northwestern Utilities Limited** / at a rate of 5.26%.
(c) Approved / E89018 dated March 22, 1989.

7.60 (a) **Town of Coronation**
RE89008 / E6.42.4
(b) For approval to enter into an amendment of a special franchise agreement to increase the franchise tax rate from 2% to 6% / **Northwestern Utilities Limited.**
(c) Approved / E89063 dated July 5, 1989.

7.61 (a) **Village of Hughenden**
RE89016 / E6.238.4
(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Northwestern Utilities Limited** / at a rate of 5.26%.
(c) Approved / E89053 dated June 6, 1989.

7.62 (a) **Village of Amisk**
RE89018 / E6.155.4
(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Northwestern Utilities Limited** / at a rate of 5.26%.
(c) Approved / E89062 dated July 5, 1989.

7.63 (a) **Town of Drayton Valley**
RE89033 / E6.46.4
(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Northwestern Utilities Limited** / at a rate of 6.26%.
(c) Approved / E89064 dated July 5, 1989.

7.64 (a) **Village of Czar**
RE89035 / E6.199.4
(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Northwestern Utilities Limited** / at a rate of 5.26%.
(c) Approved / E89084 dated September 1, 1989.

7.65 (a) **County of Strathcona No. 20 (Hamlet of Sherwood Park)**
RE89036 / E6.422.4
(b) For approval of an agreement amending the natural gas franchise agreement executed between the County of Strathcona No. 20 (Hamlet of Sherwood Park) and **Northwestern Utilities Limited** on January 25, 1988 and approved by Public Utilities Board Order E87121.
(c) Approved / E89089 dated December 14, 1989.

7.66 (a) **Village of Minburn**
RE89048 / E6.261.4
(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Northwestern Utilities Limited** / at a rate of 5.25%.
(c) In process at year end.

7.67 (a) **City of Red Deer**
RE89056 / E6.12.4
(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Northwestern Utilities Limited** / at a rate of 8.4% for residential and commercial customers and 3.09% for high load factor industrial customers.
(c) Approved / E89076 dated August 18, 1989.

7.68 (a) **City of Fort McMurray**
RE89063 / E6.15.4
(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew and amend a revenue tax agreement / **Northwestern Utilities Limited.**
(c) (1) Order E89081 dated September 8, 1989 approved the renewal of the natural gas supply and special franchise agreement.

(2) Order E89082 dated September 8, 1989, approved the revenue tax application, as amended. The City's initial franchise tax agreement had provided that City Council, in its discretion, could determine the franchise payment to be made to NUL, provided the level did not exceed 10% of the annual gross revenues of NUL within the City. It also enabled City Council to differentiate among the various customer rate groups by setting a different percentage rate of franchise tax for different customer classes. At the public hearing, the Board expressed concern that the proposed franchise tax provisions could have a negative impact on NUL's rate design, as approved by the Board at the time of the Company's last general rate application, particularly if one class of customers were to bear a much greater burden of the franchise tax load. After some discussion, the parties agreed to redraft the franchise tax provisions, to provide for

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a fixed revenue tax rate of 8.7% to be applied to all customer classes. The Board considered that the proposed level of franchise tax, as amended, was reasonable given the circumstances.

7.69 (a) **Village of Thorsby**
RE89066 / E6.300.4
(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Northwestern Utilities Limited** / at a rate of 5.25%.
(c) In process at year end.

7.70 (a) **Village of Breton**
RE89073 / E6.177.4
(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Northwestern Utilities Limited** / at a rate of 5.25%.
(c) In process at year end.

7.71 (a) **Town of Grimshaw**
RE89081 / E6.60.4
(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Northwestern Utilities Limited** / at a rate of 11.11%.
(c) In process at year end.

7.72 (a) **Town of Peace River**
RE89089 / E6.85.4
(b) For approval to renew a natural gas supply contract and to confer a special franchise for a period not in excess of 10 years and to renew a revenue tax agreement / **Northwestern Utilities Limited** / at a rate of 7.25%.
(c) In process at year end.

7.73 (a) **Town of Bowden**
RC88025 / E6.134.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years / **TransAlta Utilities Corporation.**
(c) Approved / C89007 dated March 22, 1989.

7.74 (a) **Town of Claresholm**
RC88026 / E6.37.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years / **TransAlta Utilities Corporation.**
(c) Approved / C89008 dated March 22, 1989.

7.75 (a) **Town of Crossfield**
RC89002 / E6.138.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years / **TransAlta Utilities Corporation.**
(c) Approved / C89005 dated March 8, 1989.

7.76 (a) **Town of Didsbury**
RC89003 / E6.45.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years / **TransAlta Utilities Corporation.**
(c) Approved / C89009 dated March 22, 1989.

7.77 (a) **Village of Legal**
RC89005 / E6.251.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years / **TransAlta Utilities Corporation.**
(c) Approved / C89010 dated March 22, 1989.

7.78 (a) **Town of Hinton**
RC89006 / E6.66.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years / **TransAlta Utilities Corporation.**
(c) Approved / C89017 dated May 10, 1989.

7.79 (a) **Village of Burdett**
RC89010 / E6.179.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years / **TransAlta Utilities Corporation.**
(c) Approved / C89011 dated April 26, 1989.

7.80 (a) **Village of Entwistle**
RC89013 / E6.213.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years / **TransAlta Utilities Corporation.**
(c) Approved / C89028 dated June 6, 1989.

7.81 (a) **Village of Irma**
RC89016 / E6.242.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years / **TransAlta Utilities Corporation.**
(c) Approved / C89016 dated May 10, 1989.

7.82 (a) **City of Fort Saskatchewan**
RC89019 / E6.17.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years / **TransAlta Utilities Corporation.**
(c) Approved / E89055 dated June 22, 1989.

7.83 (a) **Village of Lougheed**
RC89029 / E6.255.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years / **TransAlta Utilities Corporation.**
(c) Approved / C89046 dated October 4, 1989.

7.84 (a) **Town of Provost**
RC89031 / E6.89.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years / **TransAlta Utilities Corporation.**
(c) Approved / C89039 dated August 2, 1989.

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7.85 (a) **Municipal District of Brazeau No. 77 for the Hamlet of Lodgepole**
RC89035 / E6.473-1.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years / **TransAlta Utilities Corporation.**
(c) Approved / C89040 dated August 2, 1989.

7.86 (a) **Town of Blackfalds**
RC89037 / E6.130.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years / **TransAlta Utilities Corporation.**
(c) Approved / C89038 dated August 2, 1989.

7.87 (a) **Town of Penhold**
RC89043 / E6.135.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years / **TransAlta Utilities Corporation.**
(c) Approved / C89044 dated September 6, 1989.

7.88 (a) **County of Red Deer No. 23 for the Hamlet of Benalto**
RC89044 / E6.418-2.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years / **TransAlta Utilities Corporation.**
(c) Approved / C89045 dated September 6, 1989.

7.89 (a) **Town of Lamont**
RC89045 / E6.72.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years / **TransAlta Utilities Corporation.**
(c) Approved / C89050 dated December 6, 1989.

7.90 (a) **Town of Millet**
RC89047 / E6.139.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years / **TransAlta Utilities Corporation.**
(c) Approved / C89051 dated December 6, 1989.

7.91 (a) **Village of Acme**
RC89049 / E6.151.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years / **TransAlta Utilities Corporation.**
(c) In process at year end.

7.92 (a) **Village of Irricana**
RC89050 / E6.243.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years / **TransAlta Utilities Corporation.**
(c) Approved / C89052 dated December 6, 1989.

7.93 (a) **Village of Beiseker**
RC89051 / E6.162.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years / **TransAlta Utilities Corporation.**
(c) Approved / C89053 dated December 6, 1989.

7.94 (a) **Village of Clyde**
RC89053 / E6.192.3
(b) For approval to renew an electric power supply contract and to confer a special franchise for a period not in excess of 10 years / **TransAlta Utilities Corporation.**
(c) In process at year end.

SECTION 7B:
Applications by municipalities, pursuant to the Municipal Government Act, for approval to enter into contracts or renewals thereof, providing for the supply of light, power, natural gas, artificial gas or water to the municipality for the use of the municipal public utility.

Data reported in groups arranged alphabetically according to the name of the supplier. Individual applications within each group are then arranged in order of registration number.

ITEM NUMBER — APPLICATION PARTICULARS
(a) APPLICANT / REGISTRATION NUMBER / FILE NUMBER
(b) SUBJECT MATTER
(c) DISPOSITION / REFERENCE

7.95 (a) **Town of Lac La Biche**
RE89093 / E6.70.4
(b) For approval to enter into a gas supply contract for a period not in excess of 10 years / **Bow Valley Industries Ltd.**
(c) Approved / E89111 dated December 6, 1989.

7.96 (a) **Village of Botha**
RE89038 / E6.174.5
(b) For approval to enter into a water supply contract for a period not in excess of 20 years/**Town of Stettler.**
(c) Approved / E89075 dated August 16, 1989.

SECTION 7C:
Applications by the Minister of Municipal Affairs, pursuant to the Improvement Districts Act and the Special Areas Act, for approval to enter into contracts with utilities undertaking to provide street lighting in a hamlet situated in an improvement district or special area, or with utilities to supply light, power, gas, natural gas, water or a sewerage system to persons resident in the improvement district or special area or in any specified part or parts thereof.

ITEM NUMBER — APPLICATION PARTICULARS
(a) APPLICANT / REGISTRATION NUMBER / FILE NUMBER
(b) SUBJECT MATTER
(c) DISPOSITION / REFERENCE

There were no applications in this category before the Board in 1989.

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SECTION 7D:
Applications by users of public utilities, pursuant to the Municipal Government Act, to appeal the rates, tolls or charges of a municipally-owned utility.

Data reported in groups arranged alphabetically according to the name of the municipality to which the application refers. Individual applications within each group are then arranged in order of registration number.

ITEM NUMBER	APPLICATION PARTICULARS
	(a) APPLICANT / REGISTRATION NUMBER / FILE NUMBER
	(b) SUBJECT MATTER
	(c) DISPOSITION / REFERENCE

7.97 (a) **Town of Bashaw**
RE89094 / E6.24.2
(b) Complaint by Russell and Joan Braseth pursuant to Section 291 of the Municipal Government Act, alleging that the Town's sewer rates applicable to their mobile home park were discriminatory.
(c) Order E89112 dated December 6, 1989 found the Town's sewer rates to the mobile home park to be discriminatory. It was noted that the Braseths are treated differently than all other customers of the Town's sewer system, as they are billed in accordance with Section 3(b) of By-law 534-87, while all other customers are billed in accordance with Section 3(a) of the By-law. The Board also considered that the Town's sewer rates did not take into account the different costs involved in serving the mobile home park, in that the Braseths own and maintain their own line, and pump gray water into the Town's sewer system. The Town was therefore ordered to install a flow meter to measure the amount of waste water being pumped into the Town's sewer system by the mobile home park, and to bill the Braseths on this consumption, as for all other sewer customers.

SECTION 7E:
Applications for approval or consent for actions other than those described in Sections 7A through 7D.

Data reported in order of registration number.

ITEM NUMBER	APPLICATION PARTICULARS
	(a) MUNICIPALITY / REGISTRATION NUMBER / FILE NUMBER
	(b) SUBJECT MATTER
	(c) DISPOSITION / REFERENCE

7.98 (a) **Village of Coutts**
RE87038 / E6.194.3
(b) For approval of the termination of a special franchise agreement with **Border Power Ltd.** and fixing the price and terms of purchase.
(c) This application was in abeyance at year end at the request of the Applicant.

Section 8: Complaints Under The Nova Corporation of Alberta Act

ITEM NUMBER	APPLICATION PARTICULARS
	(a) REGULATED ENTITY / REGISTRATION NUMBER / FILE NUMBER
	(b) SUBJECT MATTER
	(c) DISPOSITION / REFERENCE

There were no applications in this category before the Board in 1989.

Section 9: Appeals Under the Natural Gas Marketing Act

Data reported in groups arranged alphabetically according to the name of the appellant. Individual appeals within each group are then arranged in order of registration number.

ITEM NUMBER	APPLICATION PARTICULARS
	(a) APPELLANT / REGISTRATION NUMBER / FILE NUMBER
	(b) SUBJECT MATTER
	(c) DISPOSITION / REFERENCE

There were no applications in this category before the Board in 1989.

Section 10: Milk Pricing

Data reported in groups arranged alphabetically according to the name of the regulated entity to which the application refers. Individual applications within each group are then arranged in order of registration number.

ITEM NUMBER	APPLICATION PARTICULARS
	(a) REGULATED ENTITY / REGISTRATION NUMBER / FILE NUMBER
	(b) SUBJECT MATTER
	(c) DISPOSITION / REFERENCE

10.01 (a) **Canadian Federation of Independent Grocers**
RE89085 / E8.4.11-19 (W/R)
(b) For approval of an increase in the spread between wholesale and retail prices of fluid milk.
(c) Application withdrawn by letter dated October 27, 1989.

10.02 (a) **Milk Producers as per report from the Department of Agriculture, Production Economics Branch**
RE89022 / E8.4.4-16
(b) The Board proceeding on its own motion pursuant to Section 12 of the Dairy Board Act to increase the minimum producer price of Class 1 milk by $0.98 per hectolitre and the minimum wholesale and minimum retail prices by 1 cent per litre, effective April 1, 1989, consequent upon an increase in the

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producer price formula as monitored by the Department of Agriculture.

(c) By Order E89021 dated March 29, 1989 the Board approved the increases in the minimum producer price and the minimum wholesale and retail prices, effective April 1, 1989.

10.03 (a) **Milk Producers as per report from the Department of Agriculture, Production Economics Branch**
RE89069 / E8.4.4-17

(b) The Board proceeding on its own motion pursuant to Section 12 of the Dairy Board Act to increase the minimum producer price of Class 1 milk by $0.98 per hectolitre and the minimum wholesale and minimum retail prices by 1 cent per litre, effective August 7, 1989, consequent upon an increase in the producer price formula as monitored by the Department of Agriculture.

(c) By Order E89067 dated July 28, 1989, as amended by Order E89068 dated August 1, 1989, the Board approved the increases in the minimum producer price and the minimum wholesale and retail prices, effective August 7, 1989.

10.04 (a) **Milk Producers as per report from the Department of Agriculture, Production Economics Branch**
RE89095 / E8.4.4-18

(b) The Board proceeding on its own motion pursuant to Section 12 of the Dairy Board Act to decrease the minimum producer price of Class 1 milk by $0.98 per hectolitre and the minimum wholesale and minimum retail prices by 1 cent per litre, effective November 3, 1989, consequent upon a decrease in the producer price formula as monitored by the Department of Agriculture.

(c) By Order E89103 dated October 26, 1989 the Board approved the decreases in the minimum producer price and the minimum wholesale and retail prices, effective November 3, 1989.

10.05 (a) **Palm Dairies Limited / Northern Alberta Dairy Pool Limited / Central Alberta Dairy Pool (Processors/Distributors)**
RE89092 / E8.4.11-20 (P/D)

(b) (1) For approval of interim increases in the retail minimum prices of fluid milk of three cents per litre effective November 1, 1989, and of two cents per litre effective January 1, 1990.

(2) For approval of a general increase in the price of fluid milk and fluid milk products, and for a price differential for milk purchased in plastic jugs.

(c) (1) By Interim Order E89109 dated December 7, 1989, the Board approved a one cent per litre interim increase in the minimum wholesale price of fluid milk and fluid milk products, effective December 15, 1989. This increase in the minimum wholesale prices resulted in a corresponding increase in the minimum retail price for fluid milk and fluid milk products prescribed by the Board.

No interim decision was reached on plastic container pricing because conflicting evidence was presented to the Board concerning the cost of these containers.

The Board noted that a one cent increase in the wholesale price of fluid milk recognizes an increase of 3.03% in the costs of a processor of milk.

The Board did not grant the entire requested increase because of various concerns it still had with respect to the application. These concerns included the allocation accounting policies, increases in certain actual and forecast expenses, actual income taxes paid, excess capacity of the industry and the appropriateness of return on sales as a profit measurement.

The interim increase was granted principally to compensate the Processors/Distributors for increased operating costs not associated with plastic containers.

(c) (2) The general price increase application was in process at year-end.

Section 11: Other Matters

Data reported in groups arranged alphabetically according to the name of the regulated entity to which the application refers. Individual applications within each group are then arranged in order of registration number.

ITEM NUMBER
APPLICATION PARTICULARS
(a) REGULATED ENTITY / REGISTRATION NUMBER / FILE NUMBER
(b) SUBJECT MATTER
(c) DISPOSITION / REFERENCE

11.01 (a) **Alberta Resources Railway Corporation**
RE89025 / E8.12.3-2(R.V.)

(b) For a review and variance of Board Order E88066 dated September 6, 1988.

(c) Order E89033 dated April 7, 1989 approved the application. Order E88066 had approved the construction of a spur rail line across a public highway in the Town of Peace River, on the condition that automated crossing protection be installed prior to the commencement of rail traffic. The Applicant sought relief from this requirement, to allow for limited rail traffic for construction purposes prior to the completion of the installation of the automated crossing protection. The Board considered that the safety measures outlined in the Applicant's letter dated April 5, 1989 would be sufficient to provide for the protection of the travelling public at the crossing, and approved the limited rail traffic movement for construction purposes during daylight hours only.

11.02 (a) **Bankeno Resources Limited**
RE89108 / E4.2639.9

(b) Application by Hydra Resources and Dorset Energy Resources to fix and determine costs or the method for ascertaining costs incidental to gathering, treating or processing gas on designated lands.

(c) In process at year end.

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11.03 (a) **Gulf Canada Resources Limited**
RE88053 / E4.1386.9

(b) Complaint by Frederick Haller pursuant to Section 10 of the Gas Utilities Act requesting the Board to fix and determine just and reasonable costs, charges or deductions for gas produced from his lands that is gathered, treated and processed by Gulf Canada Resources Limited.

(c) The application was withdrawn by Mr. E. Haller on behalf of Mr. F. Haller by a letter dated April 24, 1989.

11.04 (a) **Occidental Petroleum Ltd.**
RE89091 / E4.594.9

(b) Application by Clyde R. Schwartz to fix and determine costs or the method for ascertaining costs incidental to gathering, treating or processing gas on designated lands.

(c) In process at year end.

11.05 (a) **Small Power Producers**
NOT REGISTERED / E3.6.1.2

(b) Application by TransAlta Utilities Corporation for approval of a draft small power production contract.

(c) An Advice and Direction meeting was held October 27, 1989. The matter was resolved and a further application is expected in 1990.

Section 12: Energy Resources Conservation Board Applications

(Applications to which a Member of the Board was Assigned as an Acting Member of the ERCB)

ITEM NUMBER	APPLICATION PARTICULARS (a) REGULATED ENTITY / FILE NUMBER (b) SUBJECT MATTER (c) DISPOSITION / REFERENCE

There were no applications in this catgory before the Board in 1989.

Section 13: Gas Utilities Board Applications

(Applications to which a Member of the Board was Assigned as an Acting Member of the GUB)

ITEM NUMBER	APPLICATION PARTICULARS (a) REGULATED ENTITY / FILE NUMBER (b) SUBJECT MATTER (c) DISPOSITION / REFERENCE

There were no applications in this category before the Board in 1989.

Appendix 2

Litigation Proceedings

Appeals of Board Orders and Decisions to The Alberta Court of Appeal

ITEM
(a) FILE NUMBER AND APPELLANT
(b) RESPONDENTS OTHER THAN THE BOARD
(c) SUBJECT MATTER
(d) STATUS

1.01 (a) **Westcoast Transmission Company Limited** E4.916.88-3 (Appeal) **Husky Oil Operations Ltd.** E4.707.88-5, (Cross Appeal)

(b) Respondents other than the Board in the appeal were Husky Oil Operations Ltd., Husky Oil Operations Ltd., on behalf of the Savanna Creek Producers and the Alberta Petroleum Marketing Commission.

Respondents other than the Board in the cross appeal were Westcoast Transmission Company Limited and the Alberta Petroleum Marketing Commission.

(c) Appeal by Westcoast Transmission Company Limited from **Decision E87113** dated October 30, 1987. That decision directed the Alberta Petroleum Marketing Commission (the APMC) to credit sulphur revenue derived from processing gas originally owned by Husky Oil Operations Ltd. against the Alberta Cost of Service (ACOS) of Westcoast. Westcoast argued on appeal that:

(1) the purpose of the Natural Gas Pricing Agreement Act (the Act) is to set a price for gas not for any other product;

(2) the Board was without legislative authority to consider revenues as the Act only speaks to costs and charges;

(3) the Board was without jurisdiction to make a finding for other than the actual monthly determination under appeal;

(4) the Board was without jurisdiction to exercise its powers for the year following November, 1980, because the APMC in that year operated under the Natural Gas Price Administration Act, under which no appeal was launched.

In a cross-appeal, Husky argued that the Board erred in failing to make an award of interest on the monied held by Westcoast as a result of the sulphur revenue.

(d) The Court of Appeal dismissed the appeal and the cross appeal and upheld the decision of the Board.

With respect to the appeal, the Court held that although the Act does not necessarily deal with all substances found in raw gas, the scope is, according to s.9, "gas under gas sales contracts". The original gas sale contract passed title to Westcoast for both methane and sulphur. "Because it (sulphur) is part of the gas, its value is a factor in the calculation of costs and charges of process and transportation". The Court also stated that although the Act does not specifically refer to revenue "the calculation of total cost ... includes calculation of recovered cost if not also incidental revenue ... any other view would not respect the object of the Act, which is, for Westcoast, to assure it a fair price, but only a fair price for the refinement and transportation of the gas".

With respect to whether it is necessary that an appeal be launched for each and every monthly determination, the Court held that s.53 of the Public Utilities Board Act which provides that the Board may " ... grant any further or other relief in addition to, or in substitution for, that applied for ... as fully and in all respects as if that application has been for that partial, further or other relief" was broad enough to allow the Board to make orders for the months following the month actually under appeal.

In regard to the Natural Gas Price Administration Act, the Court considered that this statute and the Natural Gas Pricing Agreement Act must be viewed as offering one statutory scheme. The Natural Gas Pricing Agreement Act applies when Alberta has an agreement with Canada; the Natural Gas Price Administration Act applies when Alberta does not. The Court stated: "The scheme for calculation of cost of services is identical in either event, and so are the powers of appeal. We think the Public Utilities Board was entitled to treat them as one statutory scheme ...".

The cross-appeal by Husky with respect to interest was dismissed as well. The Court held that Husky had failed to present the Board with enough evidence to make a decision with respect to the question of interest and the Board's position with respect to interest was not a reviewable error of law.

1.02 (a) **Alberta Power Limited** / E3.5.3/89 (EEMA Apeal)

(b) Intervenors in the appeal were Cominco Ltd., Manville Canada Inc., and Western Canada Steel; Industrial Power Consumers Association and the City of Calgary.

(c) Appeal by Alberta Power Limited from **Decision E89004** dated February 15, 1989. The specific grounds of appeal were:

(1) that the Board erred in law or jurisdiction in its interpretation of the words "used or required to be used to provide service to the public within Alberta" in section 82(1) of the Public Utilities Board Act, when setting the price or pricing formula in which electric energy is sold to the Alberta Electric Energy Marketing Agency as required by section 13.1 of the Electric Energy Marketing Act.

(2) that the Board erred in law or jurisdiction in determining that the Board had any right or jurisdiction to rule upon whether the SPC-DC Tie was used or required on 1989 in fulfilling its duties under the Electric Energy Marketing Act, in circumstances where the Energy Resources Conservation Board had made a prior determination that the SPC-DC Tie was in the public interest approved pursuant to the ERCB's jurisdiction under the Hydro and Electric Energy Act.

(d) The appeal was argued before the Court of Appeal on May 24 - 25, 1989. A decision was pending at year end.

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1.03 (a) **Edmonton Power** / E3.16.3/89 (EEMA Appeal)

(b) Intervenors in the appeal were Cominco Ltd., Manville Canada Inc., and Western Canada Steel; Industrial Power Consumers Association and the City of Calgary.

(c) Appeal by the City of Edmonton from **Decision E89004** dated February 15, 1989. The issues in this appeal were:

(1) does the Board have the right or jurisdiction under the Electric Energy Marketing Act to determine whether a generating plant used by a utility to supply electric energy to the Agency is required to be used having regard to the wording of the Electric Energy Marketing Act and existing approvals of the Energy Resources Conservation Board pursuant to the Hydro and Electric Energy Act.

(2) does the Board have the right or jurisdiction to determine as imprudent actions by a utility in compliance with approvals of the Energy Resources Conservation Board.

(3) was the Board finding that there was no operating benefit of operating Genesee 2 in 1989 unreasonable based on the evidence before the Board.

(d) The appeal was heard by the Court of Appeal on May 24-25, 1989. A Decision was pending at year end.

1.04 (a) **TransAlta Utilities Corporation** / E3.6.3/89 (EEMA Appeal)

(b) Intervenors in the appeal were Cominco Ltd., Manville Canada Inc., and Western Canada Steel; Industrial Power Consumers Association and the City of Calgary.

(c) Appeal by TransAlta Utilities Corporation from **Decision E89004** dated February 15, 1989. The issues in this appeal were:

(1) is the phrase "used or required to be used" in section 82 of the Public Utilities Board Act to be read in a disjunctive manner, so that if a property is either "used" or is "required to be used" the Board shall determine a rate base in respect of that property?

(2) did the Board err in law or jurisdiction in the interpretation of the "used or required to be used" standard as the Board applied that standard to the Keephills/Ellerslie Transmission System of the TransAlta Utilities Corporation?

(3) on the evidence before the Board and on the proper interpretation of "used or required to be used" ought all of the capital costs as put forward by the TransAlta Utilities Corporation to have been included in the rate base amount for 1989 as determined by the Board in respect of the Keephills/Ellerslie Transmission System?

(d) The appeal was heard by the Court of Appeal on May 24-25, 1989. A decision was pending at year end.

Appendix 3

Legislative Authorities

Alberta Statutes which explicitly govern the Public Utilities Board are listed alphabetically.

1. Administrative Procedures Act, R.S.A. 1980, c. A-2
2. Alberta Resources Railway Corporation Act, R.S.A. 1980, c. A-36
3. City Transportation Act, R.S.A. 1980, c. C-10
4. Clean Air Act, R.S.A 1980, c. C-12
5. Clean Water Act, R.S.A. 1980, c. C-13
6. County Act, R.S.A. 1980, c. C-27
7. Crowsnest Pass Municipal Unification Act, R.S.A. 1980 c. C-39
8. Dairy Board Act. R.S.A. 1980, c. D-1
9. Department of the Environment Act, R.S.A. 1980, c. D-19
10. Electric Energy Marketing Act. S.A. 1981, c. E-4.1
11. Electric Power and Pine Line Assessment Act, R.S.A. 1980, c. E-5
12. Gas Utilities Act. R.S.A. 1980. c. G-4
13. Hydro and Electric Energy Act, R.S.A. 1980, c. H-13
14. Improvement Districts Act, R.S.A. 1980, c. I-1
15. Licensing of Trades & Businesses Act, R.S.A. 1980 c. L-13
16. Municipal Government Act, R.S.A. 1980, c. M-26
17. Municipal Taxation Act, R.S.A. 1980, c. M-31
18. Natural Gas Marketing Act, S.A. 1986, c. N-2.8
19. Natural Gas Price Administration Act, R.S.A. 1980, c. N-3
20. Natural Gas Pricing Agreement Act, R.S.A. 1980, c. N-4
21. Natural Gas Rebates Act, R.S.A. 1980, c. N-5
22. NOVA Corporation of Alberta Act, R.S.A. 1980, c. N-12
23. Oil and Gas Conservation Act, R.S.A. 1980, c. 0-5
24. Petroleum Marketing Act, R.S.A. 1980, c. P-5
25. Public Utilities Board Act, R.S.A. 1980, c. P-37
26. Railway Act, R.S.A. 1980, c. R-4
27. Regional Municipal Services Act, S.A. 1981, c. R-9.1
28. Rural Electrification Long Term Financing Act, R.S.A. 1980, c. R-17
29. Rural Electrification Revolving Fund Act, R.S.A. 1980. c. R-18
30. Rural Gas Act, R.S.A. 1980, c. R-19
31. Small Power Research and Development Act, R.S.A. 1980, c. S-13.75
32. Telecommunications Act, R.S.A. 1980, c. T-3.5
33. Water, Gas and Electric Companies Act, R.S.A. 1980, c. W-4
34. Water Resources Act, R.S.A. 1980, c. W-5

Appendix 4

Utilities Fully Regulated by the Board*

Electric Utilities

AEC Power Ltd.
Alberta Power Limited
Border Power Ltd.
TransAlta Utilities Corporation

Water Utilities

Acheson Park Water Corporation

Natural Gas Utilities

Bonnyville Gas Company Limited
Canadian-Montana Gas Company Ltd.
Canadian Western Natural Gas Company Limited
Elk Point Gas, Ltd.
Grande Prairie Transmission Co. Ltd.
ICG Utilities (Alberta) Ltd.
Northwestern Utilities Limited
Orr Mineral Developments Ltd.
Tilley Gas Company Ltd.

* Denotes those companies providing traditional utility services directly to end users, and whose operations are subject to the full jurisdiction of the Board.

Appendix 5

Scale of Costs

Section 60 of the Public Utilities Board Act, RSA 1980 c. P-37 states in part:

> "60(1) The costs of and incidental to any proceeding before the Board, except as otherwise provided in this Act, are in the discretion of the Board, and may be fixed in any case at a sum certain or may be taxed.
>
> (2) The Board may order by whom and to whom any costs are to be paid, and by whom they are to be taxed and allowed.
>
> (3) The Board may prescribe a scale under which costs are to be taxed."

The Board welcomes and relies upon informed and effective intervention from intervenors representing different classes of customers of a utility to test the various aspects of the utility's rate case. Any individuals or organizations including municipalities, who wish to intervene in any proceeding and who may have substantially common interests, are encouraged to combine their intervention to reduce both hearing time and aggregate costs.

Before exercising its statutory discretion to award costs, the Board will consider such questions as the effectiveness of the particular intervention, its relevancy to the issues, and whether the costs were reasonably and prudently incurred.

To facilitate the administration of claims for costs, the Board has prescribed this Scale of Costs under which costs of and incidental to any proceeding before the Board may be taxed or assessed.

This Scale will be effective for all proceedings commencing on or after May 1, 1989 and will remain in place until revised by the Board. The Board will advise all parties at the commencement of a proceeding as to whether the Board may award costs of and incidental to that proceeding.

The Board's primary objective in prescribing the Scale of Costs is to ensure that the costs of hearings are reasonable, relative to the matters involved. Costs are generally awarded against the utility, and charged to the customers of the utility through the utility's rates. For this reason, the Board considers that the costs claimed by parties to a proceeding must be subject to stringent scrutiny.

The fees and disbursements in the Scale of Costs are not intended to prescribe or limit the fees which any applicant or intervenors may wish to pay when retaining counsel or consultants. The Scale of Costs represents what is, in the opinion of the Board, a fair and reasonable contribution by consumers to provide any interested party with adequate, competent and professional assistance in making an effective submission to the Board. In a case where a party can advance persuasive argument that the level of consumer contribution is inadequate given the complexity of the case, the Board may adjust the Scale to meet unique circumstances.

The Scale sets general principles and amounts, which are to apply both to the applicant's external costs and to intervenors' costs. Intervenors are reminded that costs are in the discretion of the Board and claims will be assessed particularly on the usefulness of the intervention in testing the utility's case and thus helping the Board discharge its basic mandate to fix just and reasonable rates for all customers.

1. **Professional Fees**

   (a) Legal Counsel - Maximum Fee per each hour - $175.00.

   The fee information must include copies of all fee billings and show preparation, required attendance and argument/reply times and in respect of those categories the time spent on each major issue. In addition a retainer letter identifying the purpose of the intervention must be provided at, or within one month of, the applicable Pre-Hearing Conference.

   The Board will review the number of hours claimed by legal counsel having regard to the circumstances and complexity of each proceeding, the participation of the counsel and whether and when their attendance was required.

   The fee will be deemed to include and cover all overhead charges implicit in the normal operation of a professional office including meals. Exceptions are described under Disbursements following.

   (b) Consultants - Maximum Fee per each hour - $175.00.

   The maximum consultant's fee shall also be subject to considerations similar to those expressed above for legal counsel fees, and will require similar documentation. The retainer letter should include a description of the areas on which the consultant was engaged to contribute to the proceedings.

2. **Disbursements**

   (a) Subject to tests of reasonableness and the mandatory submission of appropriate supporting vouchers, the Board will consider reimbursement of the reasonable and prudent actual costs incurred for:

   (1) Transcript

   (2) Accommodations - during hearing days only, and excluding meals and other charges

   (3) Air fare, at economy or less, to and from the hearing, applicable only when attendance is required.

   (b) The Board will consider reimbursement of the reasonable actual costs incurred for other charges directly related to the preparation and circulation of evidence, argument and reply provided they are fully explained and, where appropriate, supported by vouchers:

   (1) Courier and postage;

   (2) Computer charges (access to databases, etc.); and

   (3) Long distance telephone and Fax.

   (c) Subject to tests of being reasonably and necessarily incurred, the Board will consider reimbursement of the following on the basis shown:

   (1) Photocopying - At claimant's cost or 10¢/copy whichever is the lesser.

Appendix 5

(2) **Road Travel - A mileage allowance of 25¢/kilometre may be claimed by participants living in Alberta but not in the locale where the hearing is held. This is payable only for the hearing days.**

There will be no reimbursement for travel costs of local participants.

There will be no reimbursement of taxi fares and parking charges.

(d) All disbursements not identified under 2(a), 2(b) or 2(c) above, will be deemed to be normal overhead costs recovered in the fee for services prescribed in 1 above.

If the Scale requires disbursement vouchers and either no vouchers or inadequate vouchers are submitted, the claimant will be notified by a deficiency letter issued by the Board. If the claimant fails to respond by the date specified in the deficiency letter, the claim will be regarded as withdrawn, and will not be covered by the payment order.

3. **Individual Intervenors**

The Board encourages intervenors with similar interests to combine their interventions. Individual intervenors interested in providing the Board with a constructive view on a particular regulated part of a utility's operations will be eligible for reimbursement of their reasonable disbursements in accordance with the Scale above. Individual Intervenors participating generally, throughout proceedings will have any claims for costs assessed on their own merits. The Board will not approve an attendance allowance.